JOINT COMMITTEE WORKSHOP

BEFORE THE

CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

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In the Matter of:                     )
                                      ) Docket No.
Preparation of the 2007 Integrated    ) 06-IEP-1F
Energy Policy Report (2007 IEPR)      )
                                      )
                                      )
Removal of Transmission Barriers for  )
Renewables and Examination of         )
Transmission Corridor Initiatives     )
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CALIFORNIA ENERGY COMMISSION

HEARING ROOM A

1516 NINTH STREET

SACRAMENTO, CALIFORNIA

TUESDAY, APRIL 17, 2007

9:33 A.M.

Reported by:
Peter Petty
Contract No. 150-04-002

COMMISSIONERS PRESENT

Jackalyne Pfannenstiel, Chairperson
Presiding Member, IEPR Committee

John L. Geesman, Associate Member, IEPR Committee and Electricity Committee

Jeffrey D. Byron, Presiding Member, Electricity Committee

ADVISORS PRESENT

Melissa Jones

CALIFORNIA PUBLIC UTILITIES COMMISSION

Paul Clanon for Commissioner Dian Grueneich

STAFF PRESENT

Lorraine White, Project Manager

Chuck Najarian

Judy Grau

Linda Spiegel

PRESENTERS

Dave Olsen
Center for Energy Efficiency and Renewable Technologies

Rich Ferguson
Center for Energy Efficiency and Renewable Technologies

Gary DeShazo
California Independent System Operator

Joe Eto
Consortium for Electric Reliability Technology Solutions

PRESENTERS

Mohamed El-Gasseir
Rumla, Inc.

Scott Powers
Bureau of Land Management, National

Duane Marti
Bureau of Land Management, California

Tom Burhenn
Southern California Edison Company

Dave Geier
San Diego Gas and Electric Company

Dede Hapner
Pacific Gas and Electric Company

Randy Howard
Los Angeles Department of Water and Power

Juan Sandoval
Imperial Irrigation District

James Shetler
Sacramento Municipal Utility District

Tony Braun, Attorney
California Municipal Utilities Association

Greg Blue
enXco Development Corp.

Rainer Aringhoff
Solar Millennium

Steven Kelly
Independent Energy Producers Association

Hal Romanowitz
Oak Creek Energy Systems

Robin Smutny-Jones
California Independent System Operator

Lorelei Oviatt (via Webex)
Kern County

PRESENTERS

Jim Squire (via Webex)
San Bernardino County

ALSO PRESENT

Nick Panchev (via teleconference)

Charles Toka
Utility Savings and Refund

Nancy Rader
California Wind Energy Association

Bill Powers
Border Power Plant Working Group

I N D E X

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P R O C E E D I N G S

9:33 a.m.

PRESIDING MEMBER PFANNENSTIEL: Good morning; this is the California Energy Commission Joint Meeting workshop of the Integrated Energy Policy Report Committee with the Electricity Committee.

I'm Jackie Pfannenstiel; I'm the Presiding Member on the IEPR Committee. To my left is Commissioner Jeff Byron, who is the Presiding Member of the Electricity Committee. To my right is Commissioner Geesman, who is the Associate Member on both of those two Committees.

To my far left is Paul Clanon who is the Executive Director Appointee Designate, I guess, of the Public Utilities Commission, who is here representing the Commission. To Commissioner Geesman's right is his Staff Advisor, Melissa Jones.

We have a very full and meaty agenda in front of us this morning on a subject that I think everybody in the room is aware of the importance. As we have looked at the issues with renewable development in California, the first reason that comes to everybody's mind and everybody's lips, is transmission, constraints on transmission. So let us spend today digging into that, trying to look for reasons and solutions that we can turn into recommendations in the IEPR report later this year.

So, we welcome everybody's participation, involvement, thoughts, suggestions to us. With that, are there other comments? Commissioner Byron.

PRESIDING MEMBER BYRON: Thank you, Madam Chairman. I'll be brief. I think this is one of my first or second IEPR workshops, and I'm learning here in my few months thus far as a Commissioner. This is what we do; workshops-r-us.

(Laughter.)

PRESIDING MEMBER BYRON: This process works really well. And I'm very interested in the presentations that I see on the agenda. Thank you.

PRESIDING MEMBER PFANNENSTIEL: Commissioner Geesman. And Mr. Clanon.

MR. CLANON: Madam Chair, first of all I want to thank you very much for me to come here and represent the other Commission, sister Commission to this one. It's not my second or third IEPR workshop. I've been to many of them over the years, and they've been very productive and very useful. And I know we'll find that to be the case as well -- Commissioner Byron.

I'm here representing both the PUC and also in particular Commissioner Dian Grueneich, who is the PUC's lead Commissioner for transmission. She was unable to be here; she really wanted to be. She tracks this very closely and carefully. And I expect with her and the other PUC Commissioners to be very engaged with you here, and to help implement on the PUC side some of the good ideas that come out of this process.

Just in two minutes, if I could, I'd like to lay out just a couple of things that the PUC has done, partly as a result of the discussions between our two Commissions and many of the folks here in the room, just in the last year or two, to try to transmission permitting at the PUC to work more smoothly, more predictably, and in particular, quicker. Because we certainly recognize the importance of transmission for all three reasons, for reliability, for cost savings, and most important for us here this morning, for meeting the renewable portfolio standard.

So, a couple of years ago the PUC over in San Francisco developed some transmission siting streamlining protocols that we worked out with our applicants, many of whom are here in this room, the investor-owned utilities that we work most closely with.

Probably the most important single thing is not rocket science, and it's kind of amazing that we didn't think of it earlier, and that is getting together with the applicants long before they file so that we can work out with the applicants scheduling and needed data and so on.

We found that those are premeetings now, have permitted us to streamline the transmission cases that we've got before us. And I think the applicants -- I'm hoping the applicants, later on in the day, when they speak will give us some perspective from their side, how it's working for them. And that effort was led by Commissioner Grueneich that she used to do that.

The other thing besides siting transmission that the PUC can do to aid this process is dollars and cents. The ratemaking of transmission is more complicated now than it was ten years ago. Ratemaking is fundamentally done at the federal level, as everyone here knows.

But one barrier that we identified along with the Energy Commission a year or two ago to the siting of transmission was concerns by applicants that people wanted to build transmission, that the FERC would not permit either some or all of the transmission --

So recognizing that, last year the PUC issued a decision; we think of it as the backstop ratemaking decision that says if transmission is needed to be built by somebody that the PUC has authority over, and the FERC is unable or decides, for whatever reason, not to build all the cost of that transmission into federal rates, we will into state rates.

And, again, I'd like the folks in the audience who are affected by that to let us know whether you think that's working, and the effect that that has.

So, the results of that have been good. The PUC has sited three major transmission lines just in the last several months, the Devers-Palo Verde II line, and also two traunches, the Tehachapi, I know were going to be talking a lot about Tehachapi, just within March, Tehachapi 1, 2, and 3, were all sited by the PUC up in San Francisco. So we're real happy that we're showing that sort of progress.

And I want to give a shout out to just the people up here on the dais who've been very instrumental in that. Commissioner Geesman has engaged with the PUC, always in a friendly manner and always with good suggestions with the PUC. And we've adopted -- we've stolen many of those good ideas, and I'm happy to say that they seem to be working. And, Chair Pfannenstiel, you, as well, have been real instrumental in helping us at the PUC get some of this going.

So let me just close by saying the last thing that the PUC is doing, the last thing in the way of innovation, is also not rocket science. And that is we've got our staff talking to our staff up there in San Francisco, folks working on transmission also now talking to folks who are the most responsible for the renewable portfolio standard, so that we don't get our left hand and right hand off in different directions.

So, again, thank you very much for letting me participate this morning; and I'm really looking forward to -- engagement here in the IEPR.

PRESIDING MEMBER PFANNENSTIEL: Thank you, Paul.

Yes, Commissioner Geesman.

ASSOCIATE MEMBER GEESMAN: Paul, in that continuation of our friendly relationship, --

(Laughter.)

ASSOCIATE MEMBER GEESMAN: -- the 2005 IEPR recommended that the Public Utilities Commission explore extending the length of time that investor-owned utilities could hold land in rate base for transmission corridors.

And in our first regulatory workshop about six weeks ago to implement SB-1059, the transmission corridor legislation, Senator Escudio carried last year, we did ask your staff if the Public Utilities Commission had a position on that recommendation. We've not yet heard back from them, and I'm wondering, is that something that's under active consideration?

MR. CLANON: It is. And it's likely to be a followup that we can be discussing post this process here in this IEPR. I think the transmission corridor process, if you were to ask me, one of the two or three things that need happen in order for the state to get the 33 percent, I list transmission corridors right up there near the top.

So, I'm expecting the PUC to be welcoming engagement with you on that, and helping develop the transmission corridors. And doing the ratemaking side of things at the PUC so that the applicants know transmission corridors will be useful to them, not just as a matter of public policy set by the Energy Commission, but also the dollars and cents that we do down in San Francisco.

PRESIDING MEMBER PFANNENSTIEL: Lorraine.

MS. WHITE: Thank you, Commissioners. And welcome to everyone to the Joint Committee workshop on the removal of transmission barriers for renewables and transmission corridor initiatives.

My name is Lorraine White; I'm the Program Manager for the Integrated Energy Policy Report proceeding on behalf of the Committee. There is a few logistical things I'd like to cover this morning before I turn it over to the technical leads for the transmission workshop. So if you'll humor me a moment.

For those of you who have never participated or been to a Commission event before, we do have a snack shop in the second floor at the top of the stairs underneath the awning. There are restrooms just out the door to the left.

In the event that we do have an emergency here an alarm would sound. And we ask that everybody calmly please follow the staff to Roosevelt Park, which is just kitty-corner from the building here, where we will reconvene until such time as we're allowed back in the building.

Because of the important nature of the workshop that we're putting on today, we wanted to make sure that we could facilitate the maximum amount of participation, so we're doing something a little bit different in this particular IEPR workshop.

In addition to having our normal webcast which allows for parties to not only see the presentations on the internet and hear the audio discussion, we're also using Webex technologies to better facilitate questions and participations by those that cannot be here in person.

We've provided in the notice extensive instructions and protocols on how to actually participate. And just a little bit here that I wanted to call to people's attention. You can follow along on the Webex by going to the link cited here on this slide, and follow the instructions and protocols.

This allows participants to not only see the onscreen slides, but then also to hear the audio, and when appropriate, to indicate their interest in asking questions or raising comments at the appropriate time.

In the protocol there are three things I definitely wanted to draw people's attention to who may be actually using this technology. And that's to use the raise-hand button when a participant would like to ask questions, particularly during the panel, so that you can alert our host, Jim Bartridge, of your interest in making comments or questions.

We will acknowledge your questions and allow you to speak at the appropriate time. This way it just helps us facilitate the discussions easier.

In addition, there can be technical

questions about how to actually participate this way by sending a message to the host by selecting the send-to-host-privately option at anytime during the workshop to get instruction from Jim on how to actually engage in this technology.

We'd ask that participants please do not send the chat message. At this particular time we'd like to just make sure that we facilitate your participation in audio questions and answers rather than dealing with just the written chat function.

So, again, I direct people to look at the instructions and the protocols for the Webex participation that's listed in this.

In particular, the development of a strategic transmission investment plan, this document runs in parallel with the development of the Integrated Energy Policy Report, itself.

As you see in the information on our web, we've put out a general calendar of what we'll be doing to develop the IEPR report including the workshops which will be held primarily April through July. And also the development of the Committee report, our target date being August 24th.

In parallel with that we are holding the workshops -- this is the second; the third will be on May 14th -- to develop the information that's necessary to go into the strategic transmission investment plan. It, too, will be a draft document published on August 24th.

Running in parallel we will be holding Committee hearings on the draft Committee report to get input from parties. We'll be holding a special workshop hopefully the week of September 4th to have a hearing specifically on the strategic transmission investment plan development.

Our target dates for publishing both the IEPR and the strategic plan are the first part of October. And we're shooting for adopting both the IEPR and the plan on the October 24th business meeting in time to transmit these documents to the Legislature and the Governor by November 1st.

All of the information about this proceeding, about the development of the strategic investment plan, can be found on our web. We have information on the previous workshops, including transcripts, presentations and general information about what was covered in those workshops available. You can also contact me in the event that you need any general information on the proceeding, itself; or who to contact about specific technical information.

For transmission as it relates to renewables, and the renewable development, I direct you to Chuck Najarian; his contact information is here, but it is also featured in the notice.

And then for the transmission corridor initiative, I direct you to Jim Bartridge. In addition, it's not featured on this slide and I apologize, but Judy Grau is the lead for the overall transmission -- the strategic transmission investment plan development. And her information is also on the web.

Today, as Chairman Pfannenstiel has indicated, we do have a lot to cover, a lot of very important information that we would like to get into our record. We're going to be first having a staff overview that will cover the issues and what we feel are important things to bring out in the beginning.

We are then going to be going into our first topic which is removing the transmission system planning and permitting and siting barriers. What those are and how that can be done.

The second topic will be focused on removing the system integration barriers. And then we go into the third, addressing regulatory barriers.

After which we will be addressing the federal and state corridor initiatives.

Our panel discussion will focus on removing barriers to meet the long-term RPS goals and getting various points of view into the record, and engaging parties in that discussion.

Afterwards we'll be opening the discussion to public comment. The way that we would like to handle these public comments is to first take questions from the dais and attendees who are here in person. And then also those who have indicated they have a question by their raised hand button on the Webex. And then if there are phone-in only participants, we'll take their comments. Afterwards, of course, we'll open it up for any closing remarks.

So I now turn the mike over to Chuck Najarian, unless you have any questions.

PRESIDING MEMBER PFANNENSTIEL: No, thank you, Lorraine.

MS. WHITE: Of course. Chuck.

MR. NAJARIAN: Bear with me while I pull up my presentation.

Chairman Pfannenstiel, Commissioner Geesman, Commissioner Byron, for the record my name is Chuck Najarian. I'm with the transmission evaluation program here at the Energy Commission.

The public notice for today's workshop states: Renewable generation targets cannot be met unless new transmission infrastructure is built. So, in other words, RPS goals are directly dependent on transmission infrastructure that does not yet exist.

Today's workshop will hopefully build a clear record of issues and actions to help facilitate construction of new environmentally preferred transmission infrastructure linking renewable generation to the grid.

The purpose of today's workshop is to support development of the Energy Commission's strategic transmission investment plan. Today we will solicit comments on actions to remove transmission infrastructure barriers needed to access renewable generation; and on how recent federal and state transmission corridor initiatives can be implemented to help achieve critical energy and environmental policy goals.

SB-1565 requires that the Energy Commission adopt a strategic plan that identifies and recommends actions for transmission investments to insure reliability, relieve congestion and meet future growth.

We have begun work on the 07 strategic plan. The plan will address recommended short-term transmission projects, corridor needs to support future long-term corridor designation, major physical and institutional barriers to new transmission development and recommended actions to resolve issues and impediments.

Today's workshop is actually a series of public -- part of a series of public workshops affording development of the Energy Commission's strategic plan. Actually began on January 16th of 2007, when we had a workshop on forms and instructions for transmission-owning load-serving entities.

On March 5, 2007, we had a workshop on SB-1059 implementation. And today we are addressing removal of transmission barriers for renewables, and examining transmission corridor initiatives.

We scheduled another workshop on May 14, 07, on inter- and intrastate transmission line projects.

Lorraine has already gone through the basic content of today's workshops. But getting into it in a little more detail, we're going to first hear about transmission system planning, permitting and siting barriers. And in this regard, Rich Ferguson and Dave Olsen of the Center for Energy Efficiency and Renewable Technologies, or CEERT, will address transmission planning with stakeholder planning groups.

And if the Cal-ISO is here today, which we believe they are, they will be describing the process used to develop their southern California regional transmission plan in the context of RPS goals.

Linda Spiegel of the Energy Commission Staff will present a stakeholder-oriented, web-based, transmission-siting tool known as PACT, or planning alternative corridors for transmission lines.

And then we'll have a discussion of all interested parties regarding the CPUC's transmission permitting process and how it can benefit from improvements in the planning and corridor designation processes.

After that we're going to be hearing from Joe Eto, a scientist with the Consortium for Electric Reliability Technology Solutions, or CERTS. He will be discussing technical solutions and policy options to address renewable integration issues.

Regarding regulatory barriers Mohamed El-Gassier of Rumla will articulate network benefits of renewables. And then we are scheduled to have the Cal-ISO discuss an update of their FERC filing for a third category of transmission projects.

Regarding federal and state corridor initiatives, Scott Powers of the national BLM team will provide an overview of the Energy Policy Act 368 PEIS project, and the federal corridors proposed for designation.

Followed by Duane Marti, the BLM California; he will be discussing how federal and state corridor efforts can work together to help facilitate orderly renewable development.

Judy Grau of the Energy Commission Staff will summarize the transmission-owning load-serving entity corridor responses to our forms and instructions. She'll be filling in for Jim Bartridge, who is operating our Webex system today.

And lastly, we're going to have a panel discuss removing transmission infrastructure barriers to meet long-term RPS goals. We have a diverse panel of utilities, developers and agencies who I will introduce individually later today.

We will be asking each panelist to respond to two questions. The first question is what are the most critical barriers to renewable transmission development and what actions can the state and other stakeholders take to help overcome those barriers.

The second question asks if it would be helpful for the state, in collaboration with stakeholders, to identify preferred renewable resource areas from an interconnection and environmental permitting perspective. And to identify grid interconnection points for the preferred renewable resource areas. And finally, to designate corridors linking the preferred resource areas with preferred interconnection points.

Lorraine has already gone over the protocol in terms of public comment today, so I won't have to address that. We have a full agenda. That concludes my presentation. And with your permission I'd like to proceed with the agenda.

PRESIDING MEMBER PFANNENSTIEL: Thank you, Chuck.

MR. NAJARIAN: Our first presenter is Rich Ferguson and Dave Olsen of CEERT.

MR. OLSEN: Good morning, Madam Chair, Commissioners, Mr. Clanon. Thank you very much for the opportunity to talk to you this morning. I'm Dave Olsen; this is my colleague, Rich Ferguson, from CEERT. We're going to do a bit of a tag-team this morning.

We'd like to cover these points. We're going to start with a brief context of AB-32 goals to ground this discussion in what we need to accomplish. We're going to review some of the tasks of proactive transmission development; talk a little bit about the challenges of involving stakeholders, increasing stakeholder participation in this effort; review some of the lessons of Tehachapi and Imperial Valley study groups; talk a little bit about what we can do to make collaboratives more effective; and especially look forward to the next set of work that we have to do.

So, to start off, Rich is going to talk about AB-32.

MR. FERGUSON: Good morning, Commissioners, Paul. Paul mentioned in his comments the 33 percent renewable goal. It's interesting after AB-32 passed, I started looking at some scenarios which some of you have seen before about, well, if the electricity sector, itself, were to implement AB-32 what would that mean.

This is one of the scenarios we looked at. My assumption is that hydro and nuclear isn't going to change much on average, at least over the 13-year planning period. This particular scenario has equal reductions in carbon dioxide emissions from coal and gas. We've looked at others.

And if you're going to back out some of

the coal and gas and you're going to meet load growth, you're going to have to add more renewables or nonfossil of some kind.

And it turns out when I ran this scenario and I checked at the end point to see well, what percentage of renewables is that; it's 33 percent.

So I asked people how this 33 percent came about, and if somebody had done a calculation like this. And I've been assured, no, no, no this was just pulled out of a hat somewhere. It's a nice and a round number, a third.

But the point here is that this is an enormous change in the system. It turns out now we have a majority of fossil power. It's nice, we have a lot of gas; it's dispatchable. But these goals that people are talking about, in the future it's going to be a much less fossil and a much more nonfossil system. I think these percentages work out to be about 60 percent nonfossil and 40 percent fossil.

The magnitude of this challenge still is sinking into me. That if you really wanted to do this, what would it take to do it. It's an enormous challenge. I've sort of racked my brain trying to figure out of anywhere in the whole world where they have changed the system this much in this short of time. And it's difficult to think of an example except maybe reconstruction after the Second World War or something like that.

So, my introduction today is really just to remind you that these goals are extremely challenging. We don't think anybody in the Legislature ever really thought much about what it would mean to do this. It's a nice kind of sounding goal, and it's our job, you know, to figure out how this happens.

Our message today is you don't change a system as big as the one we have in California, you don't change that transmission system without an enormous amount of cooperation. And I know every entity here, the Commissions, the IOUs, the PTOs, the ISO, the stakeholders, the developers and everybody else, you know, like to go off and do their own thing. And our message today is you just don't accomplish these kind of changes in a system this big without an enormous amount of cooperation.

So, Dave's going to go into the details of various programs that have worked, and what the lessons are. But I just, my point here is just to remind you that this is an enormous challenge, and we've all go to have to work together if we're going to meet these goals.

MR. OLSEN: So meeting these goals really requires building transmission to resources rather than to generators. And that means building transmission in advance of generation interconnection requests. It's a big change.

This proactive development of transmission is what we're doing with Tehachapi, what we hope to do with the Imperial Valley. It's what other states are doing, Texas, Colorado, Minnesota all have programs in place to build the transmission to resources rather than to generators.

Really, in the case of California this requires, in effect, a statewide plan that involves not only the IOUs and the ISO, but the publicly owned utilities, as well. It involves identifying, again, especially in the case of California, multitechnology resource areas, because we have very good solar potential, next to wind potential, next to geothermal potential.

It means identifying the transmission to access those resources. And as we certainly learned with Tehachapi, we have to pay significant attention to developing upgrades in the load centers at the major delivery points. It's an essential part of the work that needs to be factored in at the beginning.

Cost recovery is also essential. So, either we have to design all of our transmission solutions to being network upgrades, or we have to have resolution from a FERC-approved tariff that assures cost recovery for the needed transmission.

Involving stakeholders in this, all categories of stakeholders need to be involved here. The generators bring important technical information about the operation of their technologies. That's critical, so that in the power flow modeling those generators can be modeled accurately.

The generators also bring information about where they're planning to sell the power so we can understand more about delivery needs. And they bring information about their development schedules.

The local, state and federal agencies bring crucial information about impacts, sensitive areas, timetables. The landowners, the public interest groups bring also important perspectives. And as we've found, for example, in the case of Anza Borego, some very good ideas about alternatives that the ISO and the utilities had not anticipated.

All of this can help build more effective, more politically robust plans that have been chance of being approved. And certainly reduce the risk of delays at the end of the process. That's the hope with this involvement.

There are some real difficulties in building this kind of stakeholder involvement, though. All of the agencies have very limited staff time to devote to these kinds of planning efforts. It's been difficult for some of the publicly owned utilities to engage at all. Certainly not true in the case of the Imperial Valley study group, which Imperial Irrigation District really led with SDG&E.

But we were unable to have any publicly owned utility engaged in the Tehachapi study group at all, despite a real concerted effort to have that happen. That is a real challenge.

Another very real problem for

stakeholders is the electrical planning happens before the physical routes are studied. And many of the agencies and the NGOs, the environmental groups, don't have the staff, the technical staff, to participate in the electrical planning. They believe that they can't make real contributions there. And the future route impacts are often years away.

So in their calculation they just can't afford to devote the time to electrical planning early on in the process to help develop those solutions. They wait until routes are identified to begin participating. So they don't have much input, or it's a challenge getting them involved early on in the process.

There's often or building shared understanding of the need for some of these projects. The need for the new transmission has been a challenge, despite some active efforts on many people's part to do so. So, why do we need transmission; is it really needed in order to connect renewables. It's still in the minds of many stakeholders that's not clear.

There's also a situation where some environmental groups believe that they have a much better chance to defeat projects if they refuse to engage. And instead of being involved, they don't want to become tainted by having been involved in helping to develop solutions; they would prefer to wait and oppose the projects after the fact. They have some reason for believing that could be effective, but that's a real challenge as we seek to create more stakeholder involvement, is to get around that particular strategy that some environmental groups use.

Just to review very quickly the Tehachapi collaborative study group. This really began with a very good conceptual renewable transmission plan developed by Southern California Edison, and filed with the CPUC in 2003. The plan was good technically, but it anticipated connecting wind projects one at a time, essentially, as they were proposed and applied for interconnection.

The CPUC reasoned that that was not going to be sufficient to achieve the kind of development even for a 20 percent RPS. And in its order in May of 2004 -- it's known as the Tehachapi decision -- ordered the creation of the Tehachapi collaborative study group to develop a plan for exporting 4500 megawatts of windpower from that region. Made some specific directives to the study group which was to be led by CPUC energy division staff.

There was uncertainty about cost recovery. And Southern California Edison, in particular, reasoned that, or believed it was at risk without having more certainty of its ability to recover the costs of building this proactive transmission. And that uncertainty really manifested in the study group not being able to accomplish very much certainly in that year 2004/2005.

To help solve that problem Edison, to its great credit, developed a proposal for a new category of transmission assets, which it called renewable energy trunklines. And submitted a petition to the FERC in March of 2005. The learning from the FERC's rejection of that petition later that year formed the basis for the ISO's petition that is now before FERC to recognize a third category of transmission assets.

The study group eventually convinced the ISO to take over the study of Tehachapi and form a new process, the California south regional transmission planning process. I'll talk a little bit about that in just a moment.

Brief review on the Imperial Valley study group. It was formed about six months after the Tehachapi study group. Again, with a mandate to develop a plan for exporting 2200 megawatts of renewables from the Imperial Valley. It was led by the Imperial Irrigation District and San Diego Gas and Electric.

All eight of the transmission providers in the region were involved, along with the ISO, the CPUC, many generators, a lot of agencies, and a few environmental groups. The study group determined that it would be possible to structure the permitting for this entire multiyear, multiphase development of 2200 megawatts of renewable generation and transmission. Structure that all under a programmatic EIR for the project.

The study group then was able to put together a consensus plan that combined the Imperial Irrigation District's greenpath southwest project and SDG&E's Sunrise power link into one 500 kV transmission project, which the ISO calls the Sunpath.

Despite the active involvement of the

California Department of Parks and Recreation in the study group, the transmission line crossing the Anza Borego State Park really did not become a critical issue at the time that the study group filed its consensus plan in September of 2005.

Also at that time Los Angeles Department of Water and Power publicly announced its greenpath north project, which would export power -- which would connect the IID and the Los Angeles systems and allow power from the Imperial Valley to be exported north. So Los Angeles was not involved in the Imperial Valley study group; that came right as we were finishing our work there.

Now, what did these study groups actually accomplish? The Tehachapi study group was successful in convincing, I believe, the energy division of the CPUC to adopt a project-management approach to the development of the Tehachapi generation transmission project. And as a result of that, to appoint a project manager to have responsibility for really leading the development or helping to keep the development focused in on schedule. We think that's a significant thing that Tom Flynn, the Tehachapi project manager, has done a very good job. That's been a good move.

The study group also was able to convince the ISO to take over the planning, which we think -- well, objectively that made a big difference in speeding up the pace of the work, and developing network solutions for all of the transmission connections. That's been an important outcome, as well.

There has been some procurement as a result of coming up with this Tehachapi plan of network upgrade solutions. Most notably Southern California Edison's 1500 megawatt power purchase agreement from Tehachapi, the largest renewable power purchase agreement anywhere yet. So that's been a significant outcome.

And certainly the ISO approval of the overall transmission plan; and as Paul Clanon mentioned, the CPUC approval of the first three segments of the Tehachapi plan. Those are all good outcomes. The study group had a real role in keeping everything focused and on schedule.

The Imperial Valley study group really ended up with -- the major outcome was the identification of the Sunpath project, combining the IID, greenpath southwest and the SDG&E Sunrise power link. There's been no procurement yet.

Actually this slide is incorrect, this bullet is incorrect. There are quite a few projects in the queue. There are, in fact, 860 megawatts of projects in the IID queue. And there are about 6000 megawatts in the ISO queue for connection at the Imperial Valley substation; 3000 of those megawatts are wind projects in Mexico and about 3000 are solar CSP projects in the Imperial Valley.

The study group was, however, unable to identify any solution for getting the routing across Anza Borego. So that's -- we were unable to deal with that.

An overall outcome of this three-plus-year process with the two study groups has been, I think, to frustrate and exhaust staff resources at many of the utilities, certainly, some of the agencies and I think leave many of us with some skepticism that the collaboratives really are worthwhile when you look at what they have been able to accomplish.

Even though the collaborators were not as effective as they might have been, I think it's not a good conclusion that collaboratives cannot be worthwhile. I think the better conclusion is that they need better management and actually a lot more collaboration.

Some of the lessons here, I think if we look what we learned, first that stakeholders do provide critical information. The generators provide critical information on electrical details, on power sales, on development timetables. The agencies, of course, have a lot of critical information on impacts. So that's one thing that certainly argues for continuing to make the effort to make these collaboratives work.

A second learning, from Tehachapi in particular, is to address is to address issues that inhibit the collaboration while we're setting up the collaborative, or before we establish the collaborative.

In the case of Tehachapi the uncertainty about cost recovery really undermined the ability of that group to do much of anything at all until that issue was resolved.

A third lesson is that tasks specific work groups can be very effective. In the case of Imperial study group, for example, we set out a permitting work group which was led by Carrie Downey on behalf of the Imperial Irrigation District.

This group was very effective, number one, in informing landowners all affected, all potentially affected agencies in a very broad radius, of the work, inviting them to participate, structuring a programmatic EIR, moving forward to actually develop a memorandum of understanding for sharing the cost of all of the permitting work for the entire multiphase, multiyear project. That's an example of a very focused work group being able to accomplish a lot.

Another lesson is that these study groups need third-party facilitation. They need to be led by parties that do not have a stake in any particular outcome. And they need experienced meeting leadership to keep the meetings focused so we can limit demands on staff time, and really keep to a schedule.

This facilitation is also essential to support the stakeholders so that they can, in fact, bring up controversial issues which they may be reluctant to unwilling or uneasy to do. In the case of the Imperial Valley study group, for example, the California Department of Parks and Recreation, which has -- is very concerned about Anza Borego State Park, for example, participated in every meeting. And certainly did not bring up, in a way that caused the study group to take non-Anza Borego routes in a more urgent way, did not bring that up. So that's an example where perhaps better facilitation could have helped raise that issue earlier in the process.

I think we also have learned from the study groups that more policymaker attention is very very important to help solve some of the ongoing problems that the study groups run into, and to keep them focused.

I think we need more, we need much more collaboration, not less collaboration here. There are things we can do to make the collaboratives work much more effectively. We really have had very limited engagement. So we need, if we form additional collaboratives, we need to put much more effort; make it a higher priority to involve more stakeholders.

We need much better management of the meetings and of the process overall. We need detailed workplans with schedules that are adhered to. We need better leadership of every meeting with detailed agendas. We need minutes posted and approved by all so that the process is transparent.

All of this is essential for being able to limit the demands on staff time, so that the process is manageable for all of the parties involved.

But this experienced leadership also is required to develop the kind of openness we need, the kind of quality of involvement that really can result in a good plan.

One of the examples of a very successful collaboration and very broad involvement is the Rocky Mountain area transmission study, which was started in 2003/2004 by the governors of Wyoming and Utah.

That process involved several hundred stakeholders, all utilities in the five-state region. The commissioners attended the study group meetings personally, not their staffs, personally attended. The governors paid great attention to this. And that's one of the reasons that the RMATS process ended up with a plan that really was supported by all of the parties. So that's one of the things that we need to make these collaboratives work.

Now, there are several -- all these lessons can be applied certainly to the next planning after Tehachapi and Imperial Valley, which is going to revolve around identifying renewable resource zones and the transmission to access those zones.

Some of the work that's going on right now, or just getting started, PG&E has a new contract to rank the benefits of transmission and distribution options for integrating renewables in northern California.

Southern California Edison has an advice letter filing before the PUC right now for the study of transmission to renewables in both southeastern California, San Bernardino and in western Nevada.

Work on the IID and Los Angeles greenpaths is certainly still underway. And the ISO is forming a California subregional planning group to coordinate the planning on a statewide basis.

So all of that work is going on. We need more involvement to make this work successful and to bring it together. Certainly we need more stakeholder involvement from the generators of all the technologies to help develop least-cost renewable scenarios capable of meeting the AB-32 goals.

We need stakeholder involvement to identify the zones that best justify proactive transmission development. And perhaps the most effective way to develop consensus transmission solutions is with a new round of collaboratives that would draw all this work by the utilities and the ISO together into a statewide transmission plan.

I'd like to leave it there.

MR. NAJARIAN: Are there any questions from the dais? Any questions from anybody attending the workshop here today? Okay.

Jim, do we have anything on Webex in terms of questions? All right. Thank you.

The Cal-ISO, our scheduled next presenter, is running a little bit late. They're dealing with a security event at their Folsom facility that occurred yesterday. We expect their presenter to arrive shortly. And so in the meantime we're going to go ahead and leapfrog to

Linda Spiegel of the Energy Commission Staff to talk about the PACT program.

MS. SPIEGEL: Good morning. As Chuck mentioned, I'm here to talk about a project that PIER is working on in conjunction with the siting division. It's called PACT; it stands for Planning Alternative Corridors for Transmission lines. And it's a web-based tool for evaluating alternatives.

And it's based on -- it has two functions. It has a technical function so that the technical people involved in evaluating transmission lines can use it. And it also has an educational function so that stakeholders can better understand what's involved in that evaluation; and in doing so get a better feel for why some alternatives come out better than others.

And as just discussed by our previous speaker, the need for early stakeholder involvement in education and some kind of tool that allows this communication and analytical ability is a need right now.

And obviously state policy for the last several years has identified a need for this type of tool. The last four IEPRs have called for a process that allows California to work more effectively in the transmission line permitting and engage stakeholders early in the process; and allow for a CEQA-equivalent evaluation early in the process.

In addition, the last two Energy Action Plans have also identified this need. Transmission R&D documents have also identified this need as being critical. In the context of SB-1059 there were some early outreach to stakeholders on how to proceed with this process called early listening. And one of the issues and themes that came out of that was to recognize that early stakeholder participation is going to be key.

So what PACT does is it provides a tool that allows for a comprehensive but transparent environmental assessment. And this assessment is similar to what you would see in our siting cases. It involves all the environmental disciplines that we would use in a siting case such as biology and land use and aesthetics and cultural resources. And it has the engineering technical disciplines involved, as well.

And the idea is that it will illustrate

in a very user-friendly format a comparison of different alternatives of transmission line routes. And it does this in a manner that allows a user to see quite clearly where the impacts are for each individual discipline, or on a cumulative basis where you look at all the disciplines in total. And I'll show you some examples of this.

So it has both an educational and an analytical goal. Again, it's a web-based design; it's intended to be very user friendly, in a manner that can help the technical people get in there and really analyze their particular disciplines for each alternative route. But it also allows the other stakeholders to be able to fully understand what was behind that analysis. So that helps them understand what the tradeoffs are between different alternatives.

It also allows stakeholders to some degree manipulate the data. They can't go in and change what's important to each technical area. They can't say, for example, that wetlands are not legally protected. But they can look at it and say what would happen if we gave less significance to visual, or to wetlands, or to whatever the particular factor was. And they can look at how that would change the outcomes of that analysis.

The tool's also intended to perform for various stages from planning to permitting. So, for example, at the planning stage you could put in some very high level data that would, for example, show, okay, we have wetlands on three of these lines, and that's going to affect engineering, as well as biology. But then as you get further and further down the process and you get into permitting, you want to get a much more accurate level of data. For example, delineating the wetland. And so then you can put that information in and refine it further and further to perform at these various levels.

There's three different groups involved in the PACT project. We have the project management team, we have a steering committee, and we have several technical advisory groups. And the management team is made up of both PIER and the siting division.

We have lots of cooperation, and we're working very closely with siting division on this. We have our administrator, which is the Aspen Environmental Group. They have quite a bit of experience in transmission siting throughout the state, plus they are very actively involved with our siting division in our facility siting of generation for the last several years.

The contractors are Edison, Southern California Edison, and their subcontractor is Facet. And Edison first developed this tool. They recognized the need to get their technical people talking early in their process because otherwise they were all working sort of in isolation. And it created a lot of extra time and effort. By the time the engineers were talking to the visual people, were talking to the biologists, they realized they were all in different areas.

And so they saw the need to bring these people together early in the process and open up a line of communication. And as they were doing so, they also saw value in using it later on in the process to educate the public.

So they came to us with this and we saw the need right away. But I need to give them credit; they're the ones that first designed and developed this whole idea.

We have a steering committee that's made up of mainly project manager-level type people from a variety of stakeholder groups such as we have utilities, we have state agencies, we have federal agencies, we have the ISO, we have community groups and conservation groups. These are the people that help us guide the research to make sure that the needs of their particular agency are represented; and that this tool will, in fact, be useful for them.

We have the technical advisory groups; we call them TAGs. And these are the subject matter experts. So we have a variety of TAGs as shown here. We have TAGs for engineering, land use, biology, cultural resources, aesthetics, community, and again these are made up of the same agencies and groups that I mentioned earlier.

But these are the people that are really helping us populate the model and determine what it is that's specific to their particular discipline that would need to be taken into consideration in an evaluation of transmission line alternatives. So they're really the guts of our project.

This is just an example of how the technical advisory group will help us develop the module for their particular technical area. In this particular case the category is land use.

And each category, like land use, biology, aesthetics, engineering, they have several factors that make up their module. And these are the same factors, again, that they would use in their assessment of a transmission line in a siting case.

And in this particular example on the top it shows commercial land use. That's the particular factor under land use that we're looking at right now. And the TAGs will help us describe that factor; what's important about it; why is it important; what is the units that we would measure in making a technical evaluation. What are the sources of data; where do we get the information to populate the module. How do you calculate it and use it, you know, in some cases it's more areas are more impact. Is this a constraint; is this something that if it reached a certain threshold would not be acceptable to that technical area.

And so again the experts, the technical people are the ones that are defining these factors and defining how we evaluate it, and defining the scoring system. They are the only ones -- we call them the planners -- they are the only ones that can go in and really change these assumptions.

The stakeholders can go in and view and see exactly, again it's a transparent process. They can go in and they can see how the analysis was done, what the experts felt. But they can't go in, for example, and change anything.

So the experts tell us what's important, how do you score it, how much weight do you give it, what's the threshold. The stakeholders can look at that; they can't change those assumptions. But they can go in and get a better understanding of how we came to our conclusions.

But they also can go in and weight those assumptions. They can see what would happen. For example, if they said what would happen if I gave visual a lower emphasis, what'll happen to the segments. How will the comparative analysis change if I do that. And we call that scenarios.

They can't go in and say, okay, engineers, I think you can build on an 80 percent slope. They can't do that, but they can understand that. In fact, there was some threshold that was considered by the engineers, and then they can go in and say what if I didn't think that was too important, or I thought visual was more important.

So this is an example of how the website is going to look. Like I said, it's very user friendly and very interactive. In this particular case, on the left it's not too clear on this picture, but what we have is three lines connecting two substations in Solano County. And it's just a test case.

And what shows on this geographic representation on the left, it shows that you can actually add or subtract layers, for example, in this case the -- so here you can see that there's some layers on that are showing land use for -- this is, I think it's residential areas -- it's showing that there's wetlands in the area.

The actual lines are here, here and here. And it's also showing that there's segments of the lines. You can evaluate a route by segment; or you can evaluate a route by route, depending on what your needs are.

So the user can get in and turn these layers on and off so that they can see what it is they're dealing with. And this is like an executive summary level here.

And over here it shows a comparison of different routes. In this case it's showing segments, but it could be routes. But each color represents a various discipline. So you have engineering, land use, biology, et cetera. So, again, you can look at each impact on a single technical area basis; or you can look at it in total of all the technical areas.

And then a stakeholder can go in and again give these high level areas of engineering or land use a weight, saying medium, low or high. And then they can apply that. And then graph here will change to show the outcome of that scenario that they decided that they wanted to look at.

And you can drill down to a much deeper level. Here, again, at the executive summary you can get into each particular technical area in depth. This is an example of biology that shows, for example, these are factors that go into consideration for a biological evaluation. And underneath that it shows you what, even more level of detail of what went into consideration for these particular factors. And then it graphs that.

So, again, they can get a really good

idea of exactly what is behind each evaluation. And they can take that even, they can drill down to even deeper levels of analysis for each of those subfactors that are shown right here. So all these subfactors under -- there's biology, you have physical habitat, and under physical habitat you have things like soils. So you can drill down and look at how you might be able to -- how that evaluation was done and how you might be able to change that based on weighting.

And as you see here you have a little I button that says information. And what that does is that gives the stakeholder again the complete picture of what went into that particular factors evaluation. It gives you a definition; it tells you how it was scored, how it was calculated, and why it's important; and if it's a constraint.

So where are we to date right now? We've had two project steering committees. Roger Johnson of the siting committee is the Chair of the project steering committee. We had one early in the project. We started this project in, I think it was September, November of '05. It's supposed to come to an end in March of '08.

So we've had two steering committee

meetings. We've had them give us their feedback; tell us how we're doing; what they need to see. We're trying to get test cases from them to validate the model.

And then we've had multiple technical advisory committee meetings because, again, these are the technical advisory modules are what's going to make this model really function appropriately and correctly. And we've had several -- we just had some -- we've just had several TAG meetings that went through and identified and described those factors that I showed you earlier.

We have two test cases that we've used to date; and we're having a real difficult time getting test cases because there's a lot of sensitivity -- the utilities believe there's a lot of sensitivity in the information they have, and they're just not really quite ready to let us use them.

We have two test cases that we have used more from a functionality standpoint. We have what we call the delta project, and it's called delta because everything was changed, the names were changed so that nobody would recognize what project it was.

But the data wasn't complete. It wasn't incomplete, but some of the modules weren't as complete as you would see in a full-blown environmental analysis. So we have to put some hypotheticals in there.

We have the Solano project, which Solano County gave us a lot of GIS information they had between two substations. So that was very helpful. But, again, since it wasn't a true transmission project, we don't have the engineering data, the visual data that you would normally have in that kind of a transmission line evaluation.

But we have it and we plugged it in, and we're using it to test the model's function, the functionality. But we're very much in need of real live test cases so that we can validate the model. And we've put the request out to the project steering committees.

So the next steps we're incorporating the information that -- we've just had again a series of TAG meetings and we're incorporating all the information they've given us. We are about to put together a report that we're going to give to the project steering committee and the technical advisory committees that shows the results of their work to date. And have them again really look at the scoring and the factors that we're using to make sure that they believe that those are correct.

And we need test cases. That's another area that we're going to be really pursuing over the next couple of months.

PIER is also looking at other ways that we can use this tool, and including an assessment of potential renewable energy locations that, again, that was mentioned in the earlier project. We're talking with CEERT about pairing with them and using this model for a habitat evaluation of those renewable locations.

So, just in summary, the purpose of the PACT is to develop a decision framework to assess alternative lines, alternative routes that can be used for any footprint. It doesn't have to be a transmission line. But the idea here is to have a very technical, objective and consistent comprehensive analysis. It'll be technically sound. It'll be transparent and so stakeholders can really understand what it is that went behind that technical analysis. And so that they can better understand tradeoffs between routes.

And then it can obviously allow decisionmakers to feel very good about the decisions that they have to make down the road.

MR. NAJARIAN: Thank you, Linda. Any questions or comments from the dais? Comments from anyone attending the workshop here today? Okay, thank you.

The Cal-ISO is, I understand, about 20 minutes from arriving, so we'll proceed with our agenda. And at this point we'd like to open up the agenda a little bit and ask if there are any interested parties who'd like to talk about how the CPUC's transmission permitting process can benefit from improvement in planning and corridor designation.

First, we'd like to hear from anyone here in the audience. Okay, Rich.

MR. FERGUSON: Rich Ferguson from CEERT. Clear that we thought a lot about this in the Tehachapi process, and as Paul Clanon pointed out, there's been a lot of progress actually in this area.

If I had to summarize what needs to

happen to make the permitting process move more smoothly, it's basically we all, all of us, not just the PUC, but all of us have to be more proactive to identifying problems and solutions than being reactive.

I know we're all busy, we're all stressed out, we don't have enough staff and we're all off doing our own thing. And so when, you know, a project comes along, and we tend to wait until the problem is upon us before we react to the problem.

And that's just got to change. And it is changing. As Paul pointed out, the discussions with the stakeholders are now starting much earlier. The first problem we ran into in Tehachapi was just that the environmental contractors weren't hired in time. Again, it was a reactive process where you waited until you actually had the permit before you managed to get all the paperwork through DGS and all the other people.

But I think that has happened now. We've been promised by the Commissioners at the PUC that the contractors will be in place when the permit's there. And, in fact, I understand that there's discussions going on between the project proponents and the environmental contractors well before the PEAs come in to identify potential problems and so on. This perfect thing needs to happen.

The ratemaking issue has been identified. I'm not sure that one's been solved yet. I'm not sure that the backstop mechanism has actually been used. And until it is, we won't really know whether that's in place or not. But, at least the problem has been identified. And it was huge in the Tehachapi situation.

The other one is the project manager, somebody whose job it is to anticipate problems. A business colleague of mine said, well, if you're going to develop a new product, you should go talk to your toughest customer first. And that's a good lesson, I think. I mean in the Sunrise case we run into problems, I think, because we didn't talk to the toughest customers first, those people that are going to defend Anza Borego maybe with their lives even or something. It was a problem that was shoved under the run, and now, of course, it has to get dealt with.

And, to my mind that's the goal of these collaborative processes. It's awful easy for a utility to come up with the perfect solution for them, and run it through the process. And it isn't until it gets out in the, you know, the larger arena that you identify the -- problems are beginning to be identified. And some of them are really show-stoppers or potential show-stoppers.

So, that's, you know, our push for collaborative processes is largely so that the problems get identified early on so that we can be proactive in meeting them, rather than to have to react down the road.

So, you know, in a word, that's what I would say. But there has been a lot of movement, a lot of understanding that these transmission lines are essential to what it is we're trying to do.

The Tehachapi process, between the beginning of the Tehachapi study group process and the current in schedule that Edison has is about a nine-year process. So, we've got 13 years left, or 14 years before 2020. If we don't get the transmission planning started in the next few years we won't make it. It's as simple as that.

So, we just have to be proactive. And I

think you're all moving in the right direction.
We've just got to keep going. Thanks.

PRESIDING MEMBER PFANNENSTIEL: Rich, --

MR. FERGUSON: Yeah.

PRESIDING MEMBER PFANNENSTIEL: -- when would you start the collaboration process, the collaboration -- how do you trigger that?

MR. FERGUSON: That's an excellent question. If you think back to the Tehachapi problem there was kind of a consensus already that the Tehachapi was the low-hanging fruit. And Imperial, too. I mean there were other reasons why San Diego was looking at Sunrise and it got a lot of green cover with the renewables thing. But, in fact, that line had sort a head of stem up well before.

It's not clear, you know, what the consensus is for the next low-hanging, the next lowest hanging fruit. We think the eastern Mojave that's been identified by Southern California Edison and some others is certainly one of the high candidates.

But I think that's the next step. Is that we have to get consensus on the renewable zones that we're going to have to access. And so

I think that's the next job that needs to happen.

ASSOCIATE MEMBER GEESMAN: I guess I'd like to try and prod your thinking a bit on some of the more tangible aspects. Because consensus can be a elusive objective. Certainly your experience with the Park Department and Anza Borego would illustrate some of the pitfalls of relying on what you think may be a consensus.

How about the determination of need for a particular project? You know, Tehachapi, you guys obviously feel the project is needed. The Energy Commission's recommended it for a number of years. The Public Utilities Commission made a major push in that direction.

But has there been, other than the first three segments, a binding legal determination that the project is needed?

MR. FERGUSON: Well, I'm not a lawyer so I think I'll defer to the lawyers. But, you know, I think, if you talk to people over in the building, the various policy people, the assumption is that it is needed.

If you look at just the number of terawatt hours of renewables that we have to add even to get to 20 percent, I don't think anybody sees how you do that without it.

ASSOCIATE MEMBER GEESMAN: Yeah, and I --

MR. FERGUSON: But, you're right, one person's need is another person's, you know, fighting terms.

ASSOCIATE MEMBER GEESMAN: I would suggest there's probably a similar common assumption with respect to the Sunrise project, although I recognize there are those that disagree. But does it make any sense from a governmental decisionmaking process to allow that type of threshold decision to get deferred until the very end of the regulatory process? Can't we make these decisions in some kind of discrete segments? Get the need determination out of the way pretty early, and proceed with some of the environmental, public health and safety process that I think most of the stakeholders are most focused on.

MR. FERGUSON: That certainly would be the goal. You know, I don't know enough about, you know, how the law's been interpreted, whether or not, you know, you actually have to have a perfect complete description of the project before you can determine the need, as CEQA sees it. Or whether you can have, you know, work off some preliminary assessment of need pending the final determination.

But this issue's come up on Sunrise with the squabble between LEAPS and the Sunrise power link. I mean there are people arguing that if you did LEAPS you wouldn't need Sunrise and so on.

So, those kinds of discussions have to get resolved early, you're right. How that fits into the legal structure, I'm not prepared to say.

But I think it's possible to develop as much consensus as you can early on. Now how it runs through the legal process, you know, I just don't --

ASSOCIATE MEMBER GEESMAN: But, Paul, my recollection is that there was an effort to bifurcate, in the Sunrise case, the determination of need from a specific project route; but that ultimately the CPUC determined that that just wasn't a productive way to go.

MR. CLANON: That's right, Commissioner Geesman. And I actually want to say, first of all, that I think this is one of several exactly right questions for decisionmakers here at this

Commission and in the state, generally, to be asking yourselves.

The history here at the Public Utilities Commission is when we get a transmission line brought to the PUC by one of our investor-owned utilities the law of the State of California requires the PUC Commissioners to make three key findings in order to permit the line.

The first is need, and I'll come back to that. The second is cost. The PUC is still the ratemaking spot and the Commissioners need to make a finding that it's worth the money.

Those two, actually interestingly, have been in some ways the easiest, as we just saw with this real exciting PACT process. In many ways, it's the third finding that the environmental impacts that have been studied that has been the most difficult and the most time consuming.

It's also, by the way, where PUC management spend most of our time up until a year or two ago trying to find streamlining.

There's been some movement on need, and I want to say a couple things about that. The first is that I think we mean different things by need. I think that when a PUC Commissioner looks at the statute and what he or she is supposed to vote on, there's a very technical definition of need. And it has to do with a very particular project. That's where we got hung up on the bifurcation of Sunrise.

I don't think that we here in this room need to get hung up in that way. I think that need at the state level, particularly with respect to the RPS, means something a little bit broader. And I think that we have an organization in the state now that's very well positioned to partner with the Energy Commission and with the PUC to put the state in the position of being able to say, yeah, the state needs transmission to this resource area. And, of course, what I'm talking about there is the Independent System Operator.

I think that the ISO has really stepped up to do that. We've seen the benefit of that at Sunrise. Probably most particularly we've seen the benefit of that on the Tehachapi side.

The Public Utilities Commission I guess about a year ago now issued a decision. And I came here to talk it over in an IEPR hearing last year with you, Commissioner Geesman.

The Public Utilities Commission actually issued an order formally giving the status of a rebuttable presumption to any finding of need by the Independent System Operator. I think that comes exactly from the question that you're raising, that in the very sort of Public Utilities Code legalistic way of finding need, that happens at the very end of the PUC process; and it creates the uncertainty that I think you're very properly worried about.

And that's why the Public Utilities Commission has taken this step of saying, okay, need is larger than this one particular project by this one particular proponent. It's actually a statewide finding that ought to be made at the level of statewide decisionmakers like you here at the Energy Commission and like the folks who operate the grid.

So, a long-winded way of saying that is the right question. When should need happen and who should be making the need decision.

I just want to summarize what I was say, was when the PUC makes it need determination it does happen at the end, but it's a smaller thing. And we've made some steps to place the opportunity for the ISO, working with us and with the Energy

Commission, to bring need farther forward.

Madam Chair, I wanted also to ask Rich to comment on the second half of this question, which is let's say that the PUC has fully gotten its act together, and we've squeezed out every possible streamlining possibility in our process. What is the role going forward of the designation of transmission corridors?

And I just, as we've heard this morning, and as nobody here needs to be educated, it's the actual finding of the actual route that has been the most controversial and the most time consuming, certainly in the PUC process.

And I wonder if you'd like to comment on whether the designation of transmission corridors by the Energy Commission can be a way for us, as a state, to reduce the amount of time and reduce the amount of controversy that goes into that aspect of each individual project.

MR. FERGUSON: That's an excellent question, of course. To tell you the truth I don't know enough about how it's envisioned that that process would work.

We're looking very hard; we're getting lobbied by the concentrating solar guys that want to develop out in the southeastern California and so on.

And it's going to be awhile before we know where the best places to locate that would be. I mean we'll hear from, I hope from BLM and some of the other agencies.

But it's not clear to me at what point in the process you're going to be able to say okay, we need this kind of corridor. Because we don't yet have an agreement about where that's going to happen.

And Tehachapi was a little bit different, but even there there's a problem. As Dave Olsen pointed out, it's not clear that the corridor, the link between the resource area and the existing grid is the big problem.

We spend a whole lot more time, maybe Dave Hawkins can comment, about what the process was like at the ISO. There was a whole lot more work done on how the existing grid can accommodate this big flow of power into the Vincent substation or wherever, in Antelope or wherever it was going to go, than there was how you get from Tehachapi to those substations. I mean it was another important part.

But I'm inclined to agree that, you know, if we're talking about 6000 megawatts of concentrating solar coming into southern California somewhere, the problems are going to be as much on how you accommodate that once it's inside Edison's service territory as there is how to get there.

So, I'm not quite sure when people talk about corridors -- I mean we got the existing corridors. We know, you know, SWPPL and Palo Verde. But I'm not quite sure how you think about corridors before you identify the resource zones. Once we've got that done, you know, then that would be the next step.

So I think sort of trying to decide on what the corridors are before you know where the resource zones are is sort of got the process turned around.

PRESIDING MEMBER PFANNENSTIEL: Other questions of Rich? Is there anybody --

MR. FERGUSON: Can I ask a question back again? I mean I think Paul is right that there's the need determination, you know, the official seal of approval at some stage of the game.

But there's also a sort of a consensus

need determination that's made long before. And he mentioned the ISO process, and having sat through those meetings out at the ISO where you're sort of arguing about how are you going to evaluate this and get numbers that make this look cost effective.

It's not as cut and dried as you might think. In fact, in the end it's kind of hokey because you know, the renewables are going to displace a lot of gas. Now, how much of that is a benefit, how much of it is not, and so on and so on. It's not a cut and dried process in any stage of the game.

So, I think you're right, is that sort of the first cut is to develop some sort of political consensus, that yeah, we got to do this if we're going to reach our goal.

And once you've done that, then I think you're right, that the sort of technical need determination comes later. But it's a very political decision to get the consensus. And that's why you guys are so important.

ASSOCIATE MEMBER GEESMAN: Well, --

MR. FERGUSON: You don't agree, John?

(Laughter.)

ASSOCIATE MEMBER GEESMAN: -- you know, I think political decisions should be made by political appointees. And their appointing authority should be held politically accountable for their decision. So, I wouldn't attach too much of a stigma to that.

MR. FERGUSON: No, no, --

ASSOCIATE MEMBER GEESMAN: I do think that you draw a good distinction between what you characterize as the consensual, that can and should be made, far in advance of what I would characterize as the numerology exercise that our process currently goes through in pretending to come up with a specific answer, and ignoring the high level variability in that answer based on your input assumptions.

I think I would distinguish between the need for the particular real estate involved in a transmission project, in the land use planning decisions associated with that, which don't really benefit from very detailed numerology, and the polls-and-wires investment decision, which, to me, is more commonly a question of optimal timing than a question of absolute need.

I mean I continue to be haunted by the

language in the Valley Rainbow administrative law judge's decision where the judge said the proponents argue for a ten-year planning horizon, saying that no project could possibly be approved if you simply applied a five-year planning horizon.

The opponents argued for a five-year planning horizon because no project could possibly be disapproved if you had a longer planning horizon.

So, if our decision on, quote, "need", unquote, is really one of optimizing infrastructure investment somewhere between year five and year ten, I think we've really lost our way.

MR. FERGUSON: No disagreement. Might hear some other comments, but you know, I look at the big picture stuff first. I mean the big policy goals, whether it's AB-32 or 20 percent renewables, you know, whatever these kinds of goals are, that's the attempt to generate some sort of public consensus that this is a good thing to do.

And once you've done that, then, and as you point out, I think sort of getting the numbers that say, okay, we're going to do A instead of B, or whatever, is secondary. And we do get hung up way too much on those numbers.

And as you point out, I mean you can make different assumptions and you can get completely different results, which is just crazy.

So that's why, you know, when it -- I mean I don't know how you guys deal with that, to tell you the truth. Or the Commissioners in your shop, either. You're sort of stuck with the rules, the way they're written.

But, you know, as the Valley Rainbow decision pointed out, I mean you can set up assumptions that make it impossible to do anything if that's what you want to do.

So, I don't know how you deal with that. That's your job, not mine.

PRESIDING MEMBER PFANNENSTIEL: Thank you, Rich.

MR. FERGUSON: Yeah.

PRESIDING MEMBER PFANNENSTIEL: Are there other comments from people here on this topic of planning, permitting and siting barriers? And, Chuck, where are we with the ISO participation?

MR. NAJARIAN: I don't believe they've arrived yet. We'll continue with our agenda until they do.

PRESIDING MEMBER PFANNENSTIEL: Okay.

MR. NAJARIAN: At this point we'd like to call on any Webex participants to see if they have any comments. Please use your raise-hand function if you do. Okay, no comments from that group.

And now we will open up the phone lines for any phone-only participants, any comments you have. If you do, please state your name.

UNIDENTIFIED SPEAKER: (inaudible).

MR. NAJARIAN: Okay, you've been on muted. Any comments from phone-only participants?

UNIDENTIFIED SPEAKER: (inaudible).

MR. NAJARIAN: Okay, doesn't sound like there is. Jim, please mute those phones.

PRESIDING MEMBER PFANNENSTIEL: Excuse me, would those who are on the phone please mute your phone unless you're planning to speak. Thank you.

MR. NAJARIAN: The Cal-ISO is here. We're loading their presentations.

(Pause.)

MR. NAJARIAN: Okay, sorry for that. Gary DeShazo of the Cal-ISO is now prepared to make his presentation on the first part of our agenda here.

MR. DeSHAZO: Well, first of all, I'm not used to having people wait on the ISO; usually we need to be out in the front of things. And let me just extend my apologies for being late. Of course, there's been, you know, some extenuating circumstances. As it turns out, I got a double-whammy primarily because my Vice President, Armando Perez, is in Europe for three weeks for a well-well-deserved vacation. And so I'm glad he was there and not here. And so I have been serving in his capacity.

And then I had volunteered for another fellow that was Executive in Charge, who's also on vacation, so I volunteered to take over those duties.

So that bring a whole new concept, I guess, to volunteerism with regard to things that happen.

PRESIDING MEMBER PFANNENSTIEL: Well, thank you for joining us with all of that going on. We appreciate it.

MR. DeSHAZO: And I do want -- I could have delegated this, but just let me say that this is very important to me as part of the overall leader in the transmission planning process within the ISO. And it's also very, these proceedings are very important to the ISO. And I felt that it really was, it was important for me to be here to provide you some comments, rather than delegating this to someone else. So, I appreciate your indulgence.

As I was looking at the questions that I was asked to address, I guess there's a couple of areas, have an update on the third transmission type; I think that comes later on today. But the initial part, or the first presentation was related to the CSRTP process and the ISO's planning process.

And the questions that were posed to me was one, a little bit of background about the CRSTP process; and then its relationship to the new California ISO's planning process that we have implemented.

With regard to CSRTP what started this process was three major transmission projects that were being proposed in the southern part of

California. These being the Sunrise power link, which is being proposed to help deliver renewable energy from the Salton Sea and solar generation from the Imperial Valley.

There was the Tehachapi project which is for the wind generation. And then there was a LEAPS project which is hydro.

Now, all three of these projects are significant project types and clearly they have a role to play overall in the strategic development of meeting our resource needs in California, plus also the transmission that's needed in order to be able to deliver these resources to load.

The CRSTP was formed as a way to manage the overall process of how do you look at these projects together, and how do you look at them separately.

And so CRSTP was there to help review and assess and validate the potential system improvements that would be required for the project proposals.

Now, they had transmission configurations in place. The key was because transmission interacts, ties the system together, the question is are these transmission proposals singly that were defined for these projects really the best overall plan for interconnecting all three projects into the system.

There was also the need to make sure, in counting for the individual needs of the projects, that there was sufficient transmission in place to meet the requirements of what they were looking for.

And then overall the ISO Board of Governors was looking to have some way for ISO Staff to be able to provide them input, discussion and recommendations on a transmission proposal for the projects, both really overall as all three projects together, and singly each one by themselves.

The process has taken us through, basically through the course of 2006. It has led to an approval by the ISO Board of the Sunrise power link. It has also led the ISO to move forward on how to deal with LEAPS, which is a pump storage project, and the issues surrounding that in terms of who owns it, who operates it, how's it interconnected with the system. It's led the ISO to initiate a formal stakeholder process to look at both operational control and rate treatment for this project.

Tehachapi, another big thing that has been around for a couple of years, has led to approval by the ISO Board in January of this past year. And, of course, the ISO is involved in participating in the CPCN process for this.

Now, having said that, and thinking in terms of what the CRSTP effort did, which was focused on these three projects, let me just turn for a moment to the ISO transmission plan.

Now, the ISO transmission planning process really is a culmination of an effort that was started between the ISO, the CPUC and the CEC several years ago in looking for ways to better coordinate the overall planning, strategic planning for transmission needs across the State of California.

What we did in working with the agencies, with the regulatory agencies, yourself and the PUC, as well as with the participating transmission owners, at least the larger ones which would include San Diego Gas and Electric, Southern California Edison, and Pacific Gas and Electric, was to look for a way to one, try to streamline our planning process.

Now, what we had been doing in the past is that we had been collecting transmission plans from each of the PTOs. And this is done on an annual basis. While the ISO was overall involved in these processes, the PTOs really were the ones that, you know, they perform the analysis and they prepare the documentation; and they would submit their transmission plans to the ISO for approval.

What this ended up being was a situation where the PTOs were bringing individual projects to the ISO for approval. Clearly there are those that are 20 million or greater that need to be approved by the board of governors. But there are many many more projects that the PTOs would be proposing in order to meet the overall reliability requirements for their service areas.

So, we were in this process where they would provide us a plan and we would look at each one of these individually. While there was work, I think, done both within the PTO area, as well as the ISO, relating to operational concerns and issues, there really wasn't anything in place to help us manage how do we deal with issues like, for example, the peak that we had occur on July 24th of last year.

Now, clearly we made it through that, which was fine. But, as a planner, I need to be constantly looking forward to try to first determine whether or not I have issues next summer that I should be looking at; or is there anything that I can do today to help maybe resolve problems that may have occurred.

The thing about having a system peak like we had is it tends to bring all the load out of the closet, so to speak; it tends to uncover issues that maybe we may not have necessarily seen.

And so the key was that what you need to have is something, a coordinated process in place that can take a look at those things and be able to make decisions about how do we prepare for next year. Is there transmission infrastructure that's required. If there is, then is it the economic thing to do. If that's the case, then how do we get that programmed into transmission planning.

Now, I think that one of the -- I think the telling points about our little process was that the ISO did not have a transmission plan. We coordinated transmission plans, but we did not have one.

And if you look at the other ISOs across the nation, I believe that we were probably the only one that did not have a transmission plan, which Yakout fixed almost immediately once he arrived at the ISO.

So our new planning process was really to take what we had been doing and try to then start to focus that towards a single transmission plan. We tried to focus on being able to put all of the projects that are being proposed, either by the PTOs or the ISO into one location.

We also wanted a place to be able to focus on operational concerns. And so we wanted to make sure that that was covered so that there was a clear picture to the stakeholders that there was, indeed, a tie between what we see happening across a peak and issues that we discovered there and how that translates into something that being done to address that.

So, overall, the idea was to focus on a single plan. Focus on a single location that the ISO, in partnering with the PTOs, then would prepare on an annual basis.

Finally, the key is then would be subregional planning, which I think I have, from time to time, spoken about here at this podium. Certainly I've been out in other places talking about subregional planning.

I am an avid supporter of this. I think it's absolutely the right thing to do. And I believe that coordination across the entire State of California, which includes all the entities, is absolutely essential for us to be able to get a clear and a fair picture about how we need to move strategically forward in transmission.

So, if we look at a comparison between the two processes, I think you can see that there are definitely some differences. Now, I'm going to skip this next slide because this really gets into more details about what's in the plan, in the ISO transmission plan.

But the point is there's a lot of information in there that is helpful to a lot of different types of stakeholders, depending on who you are. And that's the point.

But, in terms of the ISO's planning process, it needs to be, and is, forwarding looking with a planning focus as a clarity on process and a commitment to transparency.

Now, this latter part, while we have

been always involved with stakeholders, I believe that as we have looked at our overall process and how we do planning, that there are some gaps that needed to be filled.

And so while we had been doing, I think, a good job, or an acceptable job at transparency, I don't think it was good enough. And we need to do things better.

That we need to have a proactive involvement with the regulatory agencies, the Energy Commission, as well as the Utilities Commission. We're interested in our process being able to provide some early information to the PTOs on transmission investment. And a commitment to subregional planning.

Conversely, on the CRSTP process is it was really -- it's locally focused; it was locally coordinated. There was some subregional involvement, but really it was at that local level.

Overall, the intent, at least as I see that process, is it integrates, as I would want, a right into the overall ISO's planning process, as well as subregional planning.

I think that the ISO's transmission

planning process has to be flexible enough to allow, to collect and have participation by a broad range of stakeholders. But clearly, as we have seen with Tehachapi and Sunrise and LEAPS, and as we will maybe hopefully see in areas in northern California, as well, that there are some specific areas that require specific attention. And that's okay. You need to have that.

The thing that -- I think the question that I maybe tend to wrestle with more than any is that we had STEP out there, the Southwest Transmission Expansion Plan. It was really organized in the very late 2002, early 2003 timeframe.

So the question that I often get asked is why didn't you just coordinate that through STEP. That's a difficult question to answer, but I think that at least in my opinion, where STEP was at the time we needed to perform the type of analysis that was required for these three projects, I just didn't believe that STEP had the organizational structure to be able to accomplish that.

It started out to be that way. But it really, as we worked through the short-term upgrades that have been now implemented across the east and west of the river transmission paths, it sort of lost its way.

So STEP was put in place specifically to address these projects, to keep a focus on these projects, and to allow for the PTOs and other stakeholders and project participants to be able to support the process and looking at how we can integrate the transmission plans together.

So I think that you will see, and the ISO supports, the formation of these kinds of groups in the various subregions, you know, based upon certain interests in developments that are occurring.

I would expect and hope that information gets fed into the ISO transmission plan so that we can make sure that it's in a single place; that there's an opportunity to look at that information and compare that to other information that's in there. So, it ha a home there, even though it's on a small region.

Now, at the same time, I think we can say the same or really make the same, I guess, draw the same picture with regard to the ISO transmission plan. It needs to go someplace. We only represent the ISO's control area and those that are involved in that. And while we invite others to participate in that process, and we do get some participation, the key is how do we tie the rest of the overall California infrastructure into that. And that's where the subregional planning group goes.

So you can sort of see a process here where you have smaller groups like CSRTP that are focused on specific things, that feeds into the ISO's transmission plan, that's culminated there at the ISO's transmission plan that gets fed into overall the subregional planning process. So that where everybody else then provides their plans. And at that point then they can all hopefully get brought together.

Subregional planning process, as I said before, is necessary, I believe. And as I said before, I'm a supporter of this. I think it's the right thing to do. And I believe that that's where the different interests can be brought together in terms of what we're trying to accomplish across the state.

This last slide really goes to is there an expectation that this will support the process with regards to coordination of renewables. And I think absolutely yes. I think that all three of these processes, whether it's at the CRSTP level, to ISO's planning process, to subregional planning process, the key is there's coordination. The key is that there's information that's being passed from one to the other. The key is that there are decisions that are hopefully being made with the full knowledge of other things that are going on. With full stakeholder participation, so they have opportunities to participate and provide their input into that.

And so if we can get this process up and running, and I believe that we're very well along the way to making that happen, that, in fact, that it will support the overall coordination and the process. Not only for just our transmission needs, but for the integration of renewables, as well. And I think that's really a very important aspect about the overall process.

That concludes my presentation.

PRESIDING MEMBER PFANNENSTIEL: Thank you. Questions? Commissioner Geesman.

ASSOCIATE MEMBER GEESMAN: Gary, thanks for being available to us under a difficult set of circumstances.

And I also wanted to congratulate you and Yakout for the 2007 transmission plan. I recognize it's really the first effort, and you've got aspirations to build upon it. But I think as a first effort, it's quite an improvement. And certainly embodies the cooperation, collaboration that you've tried to accomplish with two state agencies.

Before you got here I had expressed some concerns about the way our decisionmaking process addresses the question of need for particular projects. And in looking at your 2007 plan it kind of leaps off the page, page 25, as to who makes that decision, when that decision gets made for a project that requires a CPCN.

Your plan actually has, I think, what at least to me appear to be a couple of contradictory assertions on the same page of the first part says the CPUC review of the LSE's procurement plans involves the evaluation and potential approval of opportunities that displace or defer transmission projects with nonwires alternatives.

And then the footnote to that sentence says that by virtue of filing for a CPCN the project has already moved beyond an analysis of a nonwires alternative.

I think that's probably the way you'd prefer it to be, but isn't it true that, you know, the PUC has in front of it at any parties' ability to raise question of nonwires alternatives, or whether a project that your plan has approved is truly needed and should be approved at the CPCN stage.

MR. DeSHAZO: Well, I hope those are the only two contradictions that you've found.

(Laughter.)

MR. DeSHAZO: I'm sure there's probably a few more in there.

But, as we were putting the overall process together, we were pursuing two parallel paths. One for the planning part and the other for how do we address the overall procurement process and possible nonwire solutions of that.

We never finished the latter part. We had proposed, as we were working through the process, that we would somehow come up with a transmission plan that would be, I think as Yakout has put it, the ISO would develop a reliability benchmark, a reliability solution to the transmission needs.

And it would be done most likely with transmission or transmission type of infrastructure.

So that would be a solution then that would be passed forward to go through some type of analysis where they would maybe look at some of the components of that plan and decide whether or not there would be some nonwires opportunities that possibly could displace that.

We ran into some difficulty because of the perception of passing a plan through the PUC and having something come out of that that was different than what went in. It looked like that planning was actually being done at the Utility Commission level. And that wasn't very palatable to the IOUs.

Now, that was not what was intended at all. And I think that that was well understood, but there was still the perception that that was there.

That part we need to work on, because clearly what you could want is the economic choice to be made in terms of what's the right thing to do. If generation is the right thing to do, and economically it's the best solution, then it clearly should have the opportunity to do that.

But he's also said that if generation intends to solve a problem that a transmission project is solving, we all know that siting transmission is five to seven years or possibly longer; and his expectation would be that the generation would need to make some kind of a commitment to assure us that it's going to be there when the problem arises.

I don't have a clear answer for you there, Commissioner, simply because we haven't yet gone back and picked up that conversation again in discussion between the ISO and the Energy Commission and the Utilities Commission about how to work through that.

We know a little bit more today than I think what we did when we first put that together, but it still is an open-ended question.

ASSOCIATE MEMBER GEESMAN: Yeah, it strikes me that the law can operate, though, to frustrate even the best intentions of well motivated people, and well motivated agencies. Federal law, I think, makes quite clear that those sorts of need determinations are supposed to be made by the ISO under your FERC tariff. I don't think there's much question about that.

On the other hand, your determinations have no significance under CEQA at all. State law makes pretty clear that the CEQA decisionmaker is supposed to make those determinations. It strikes me that the real challenge in front of us is figuring out some way to intertwine those two processes so that your decisions have some state law significance. And the state can proceed on the basis of the analysis that your agency performs.

MR. DeSHAZO: And you're correct with that, that is something that tends to come up more and more often in discussions. We have a rebuttable presumption for economic projects that was provided, at least provided, laid before us by the Commission as one way to address economic projects.

ASSOCIATE MEMBER GEESMAN: And that's fine until somebody rebuts the presumption. You know, in the --

MR. DeSHAZO: Right.

ASSOCIATE MEMBER GEESMAN: -- judgment of an administrative law judge, and the procedure is such that you always let the evidence in, you always let the evidence in. So it strikes me that we end up chasing our tails until we figure out a way in which to crack this particular conundrum. It's a conflict between federal law and state law.

MR. DeSHAZO: I understand.

ASSOCIATE MEMBER GEESMAN: Thank you.

PRESIDING MEMBER PFANNENSTIEL: Further questions here? Thank you. Are there other questions? Rich.

MR. FERGUSON: Gary, I'd just like to thank you, too, for taking the time to come down. Yesterday must have been a nightmare.

In following Commissioner Geesman's question, there's another problem which is maybe even more serious between sort of who has the last say on a plan. And it's another factor that's going to make it difficult to sort of get the federal rules and the state rules lined up.

And that is when we're talking about renewables, I mean that's an energy planning decision that the state has made, or is in the process of making. But it's nowhere to be found in the Federal Power Act.

So, you know, we tried on all three

projects in the CSRTP to hope together some kind of numbers that gave some, you know, reasonable weight to the fact that you were -- these projects made it easier to incorporate renewables into the mix.

But, you'll have to agree that that was not an entirely satisfactory exercise. And it was pretty ad hoc. But that's sort of a fundamental problem in trying to line up what you can do under the federal tariff, and what needs to happen under CEQA.

And I just wondered if you have any thoughts about, I mean I thought the ISO Board handled it very well in all three of these cases. But I think everybody would agree, was kind of an ad hoc solution to the problem.

You know, if we're talking about really sort of significant changes in the grid to accommodate say, as much as 33 percent renewables, we're going to have to solve this problem.

I'm just wondering, have you, since we dealt with those three projects, has there been any more thinking inside the ISO about how to accommodate the state's energy planning decisions into the decisions that are made in your transmission planning process.

MR. DeSHAZO: Well, and I could be way off base here, but I think the thing that just comes into my mind is looking at our third transmission type. We believe that that's very important. We are clearly, and I've got a short presentation later, just to provide a little bit of information about that, but clearly we want to move forward with that.

As a transmission planner I'm looking at how do I make this work. I mean, do you just build a bunch of stuff out there. I think there has to be more of a coordinated effort in order to do that.

If we don't have something in front of us that coordinates our overall planning efforts, that integrates the interest and desires of stakeholders, the types of decisions that are being made by the Energy Commission in terms of things that they would like to achieve, if we don't have that somehow coordinated into one place, then I think what you have is essentially while there was good work done on CRSTP, it came hard and it came quickly with a lot of interest. And I think it's one thing that got away from us because there was nothing in place to help us manage that. And that's what we're trying to accomplish.

MR. FERGUSON: Yeah, well, we look forward, of course, to continuing to work with you on that. I mean the third transmission, or whatever we're calling it, doesn't really address sort of the network issues, I mean sort of the renewable gen tie kind of thing.

But, you know, along with Commissioner Geesman's, the line, the interests under federal and state law, I think that's an important thing that we're going to have to figure out. It may be that there won't be, you know, a landmark decision that's going to provide a formula for all time. We are just going to have to work it out.

But it's something that absolutely is going to require coordination between your top management and these guys and the people down in San Francisco, too. So, I hope that occurs.

MR. DeSHAZO: Well, you know, if I'm successful at bringing my coordination part on the planning part of it, okay, it's easy to focus on that because that's what people see. If we could take that out of the equation so now that the only thing that's left is the issues that you're raising, then, you know, I think that that's where they'll need to focus their energies.

Because, in the end, it doesn't matter what I do in terms of trying to coordinate transmission if it doesn't take us anywhere. If we don't get anything that's valuable out of that. Or put something together and just simply get stopped someplace and you start to ask, what's the point. So I think there's some recognition that that's there.

PRESIDING MEMBER PFANNENSTIEL: Thank you, Gary. Chuck, should we move on to the next section, or are there other questions? Oh, I'm sorry, go ahead, Dave.

MR. OLSEN: Dave Olsen from CEERT. Gary, do you intend to involve stakeholders in the development of both the annual statewide transmission plan and the California subregional planning group? And if so, what categories of stakeholders, what forums, what venues, frequency, what quality of involvement are you looking for?

MR. DeSHAZO: Okay, actually all, should be all. Let me tell you how we're proceeding with the ISO's transmission planning process. We've got, you know, a diagram that's out there that we've put it out for quite some time. It shows swim lanes and the intent is to try to show the relationship between the ISO and the CEC and the PUC and the publicly owned utilities and others.

Clearly, at least in my vision, is that in trying to bring us to a common transmission plan we really need -- there's a lot of other things that need to be brought to a common point.

And let's just go to, for example, assumptions. And the concept is if we can develop a set of unified assumptions upfront that then you take forward into your overall planning process, then when you get to the end it would suggest that somebody that sees the answers and may not like the answers can't then raise the issue, well, I don't like the load forecast that you used in terms of performing the analysis.

And so what we're attempting to do, and at least what we are doing, is working with the PTOs developing a single study plan for the ISO-controlled grid.

Now, in terms of assumptions there are a number of types of assumptions that can be coordinated across the entire grid. You know, for example, we're all going to use the same criteria, we're all going to use, maybe start from the same set of basecases; we all agree that we're going to start with a load forecast that really was developed by the CEC and is manipulated to meet the needs for the different service areas.

So there's different things that can be done upfront, and we can agree on upfront. And then each of the PTOs then they have their own unique things that they're doing in their service area, so -- and they may have certain things that they're each doing that are spelled out separately.

But the point is that there's a single study plan upfront that gets put in front of the stakeholders where they have the opportunity to provide input to that; make suggestions in terms of changes; maybe changes in modifications and objectives or whatever it may be.

But in that study plan it says, this is what's going to be done. This is how it's going to be done. This is the timeframe by which it's going to be done. And there's going to be a certain time when that stuff is completed.

And through that process will be

stakeholder meetings.

The ISO, any stakeholder can attend an ISO stakeholder meeting. And so they're welcome to provide their input. So that's how I'm hoping to address that process. So we make sure when we have the ISO transmission plan, it's had that input upfront.

The subregion planning process essentially is the same thing. That we need to work with various entities across the state about things, because I'm not quite sure people are -- I think they're interested -- well, they're all interested in doing something. But they're not quite sure about what's the best way to do that.

But in the end, if you look at what's being done in the southwest and other places, clearly what makes these things work is involvement by stakeholders.

MR. OLSEN: Have you had any of these, any opportunities for stakeholder input on assumptions and study plan to date?

MR. DeSHAZO: No. But it's coming. We're late simply just -- we're just late. We've had some hurdles that we've needed to get over.

We met with all of the PTOs, not just

the large ones, but all of the PTOs, in January. And I intend to make this an annual event. So that the PTOs get together and they put, you know, they sort of start to draft out what they think the study plan should be.

And once we get that in a draft form, then we would hope that by April of every year or maybe even possibly March of every year, that that would be distributed to the stakeholders; and then give them several weeks to look at this thing.

We'd have a stakeholder meeting where we'd gather input on the study plan. Now, there are aspects that save time, the PTOs are still performing their analysis, and they have their own study plan. So they'll probably have some local stakeholder meetings, as well, where they would gather input. But the thing that all gets fed back into the study plan.

So, we've got a draft one out that's being reviewed by the PTOs right now. I hope to get this out this month. I believe that we're hoping to schedule some type of a meeting in early May from this.

PRESIDING MEMBER PFANNENSTIEL: Thanks. Where are we, Chuck, on the schedule? Thanks, Gary.

MR. NAJARIAN: Commissioner Pfannenstiel, we'd like to try to get through two more presentations before we break for lunch if that's okay with you. We can see how the next two go.

We've got Joe Eto and Mohamed El-Gassier. Before that we actually have some Webex questions. One individual on the Webex would like to ask a question at this time.

Nick, do you have questions?

MR. PANCHEV: My name is Nick Panchev. Can you hear me?

MR. NAJARIAN: Yes, we can.

PRESIDING MEMBER PFANNENSTIEL: Yes, we can hear you.

MR. PANCHEV: Thank you. Here in my room is our Chief Legal Officer, Mr. (inaudible) Watson, and the rest of the officers.

On behalf of all of us we would like to express our concerns and, of course, we honor to comment on the subject topic.

I have a general and specific question (inaudible) to me. First of all, my understanding is that the whole process supposed to be a streamlined process rather than expanded. We are speaking here of two sequential years, 2010, 2015 and 2020. I may be still around 2010, but I'll not be around 2020.

So, what we have here on the table is a renewable in this particular case, solar-thermal power plant, that they can go anytime. But we don't have the ability to prepare all the necessary request for proposal due to uncertainties. And I can (inaudible) huge volume of proposals here.

And two, considerable (inaudible) in regards to (inaudible) transmission lines by the Southern California Edison which will be lacking thereof from our proposal which is due in less than 30 days, to uncertainties about cost, obviously stakeholders (inaudible) wants to know, when, how much, in order to result into our proposal before the IOU (inaudible) the QRF. This is a very critical items that here we are investing in (inaudible) equity in general.

There are so much things to address here, it looks like there are a couple pioneers here to do after a decade and a half, solar thermal plants. And those are real IPPs compared to, in my opinion, our opinion, Sterling and Edison Company, that's a different setup. Different type of a IPP.

So, what you have before you (inaudible) project, there are tables, but they are lacking data, adequate information to complete the project. So the basically hurdle here is how do we achieve expeditiously all those things without -- and so we can online in 2010. So presumably (inaudible).

We cannot speak anything on behalf of anybody else, but I believe there are two good projects, pioneer projects to be done. And they are solar turbines, -- technology (inaudible).

So, we would like to (inaudible) as expeditiously with the Commission and ISO and everyone else, of course, Southern California Edison, see how to expedite or we'll be forced to delay again a certain time to unknown time.

Again, streamlining the process rather than extending it, I believe. We would like to -- we are (inaudible) that we will be doing this project, but we need to answer before the stakeholders (inaudible) how we'll do it, how much (inaudible).

Thank you very much for everything, and we hope to communicate to you, if it's any day, every day, doesn't matter. That's always done. Thank you, Commissioner.

MR. NAJARIAN: Nick, could you do us a favor and identify who you're affiliated with? Nick?

MR. PANCHEV: My name is Nick Panchev; I'm the Chief Executive Officer of Angosystem (phonetic) Solar Electric and Power Plants Components, Inc. Angosystem Solar Electric is to be the developer and operator and power plant components is to (inaudible) technology.

The officers here are myself; Lovine (phonetic) Watson, Cheryl deBohn (phonetic) and Chief Legal Officer Peter Sanchez, President Rudolfo (inaudible); Chief Financial Officer Verando (inaudible); Chief Operating Officer --

MR. NAJARIAN: Nick, Nick, that's --

MR. PANCHEV: -- Jonal Odell (phonetic), Vice President.

MR. NAJARIAN: All right, Nick, thank you. We will encourage you to put your comments in writing and we'll be dealing with those offline.

MR. PANCHEV: Thank you.

MR. NAJARIAN: Thank you, Nick.

All right, back to the business at hand. We were hoping to get through two more presentations before lunch. If you'd like to give that a try we'd like to proceed.

PRESIDING MEMBER PFANNENSTIEL: Let's proceed.

MR. NAJARIAN: Okay. Next up we have Joe Eto of CERTS. Joe's going to be talking about transmission integration barriers work he's been conducting. Joe.

MR. ETO: Thank you, Chair Pfannenstiel, Commissioner Byron, Commissioner Geesman, Ms. Jones, Mr. Clanon. Appreciate the opportunity to speak before you today. I will attempt to be succinct, recognizing that I'm separating you from your lunch hour.

The work that I'm going to talk about is inspired by the recognition that prudent facilitation, a substantial increase in renewable resources requires proactive identification, analysis and development of options to address potential operational and resource integration issues that might otherwise hinder or delay the achievement of statewide policy goals for renewable energy development.

In this regard I'd like to acknowledge our gratitude for the support of the PIER program, for supporting the research that we'll be conducting to bring information into this decisionmaking process.

I'd like to recognize Clare Laufenberg-Gallardo for her project management of our activity, as well as Dora Yen from the PIER renewables program with whom we've been coordinating very closely.

I'd also like to acknowledge my colleagues, Jim Dyer and John Ballance, from the electric power group. They are doing the heavy lifting on this project. Schedule conflicts prevented them from being with us today. However, they're participating by the Webex.

This work was inspired by a project that we conducted two years ago for your IEPR in 2005, in which we took an expanded look at, in anticipation of some of these operational integration issues. This consisted of a literature review, a specific focus on the European experience, and a lot of discussions with stakeholders here in California.

What's unique about the work that we produce was not so much that we found something new or unknown about renewable integration, but we were able to set it in a very California-specific context of the types of issues we'll have to address here in California.

I think what's notable about the work is the identification of policy objectives and recommendations on how to go forward in trying to address these operational integration issues, as well as some of the stakeholders that we think needed ownership of those issues going forward.

This research really is inspired by the research activities that we identified in that project, and that we're hoping to bring new information into this IEPR process as part of that activity.

In this regard we've also been very closely coordinating with the intermittency analysis project whose more detailed quantitative findings will certainly help guide some of the work that we'll be doing in our project.

This project is currently in progress, so I'll be giving you primarily a project update and a status report. But because of the needs of the process, we'll be trying to provide interim information into the IEPR process for inclusion in your report. So I'll also talk about expected project outcomes and the milestones.

Two years ago we identified nine reliability and operational issues for integration of renewables. And I want to identify and discuss each of them individually because this really provides a technical basis for the work that we'll be doing this year.

Load following refers to essentially the difference between the minimum and the maximum load, and essentially how much generation needs to be available to meet the ramping up of loads over the course of the day.

The integration of renewables, which we take essentially as a must-take type of resource, can either exacerbate or decrease that swing between the minimum and the max. And looking at that difference and how that changes over time is a key issue for having how much control of the generation needs to be online to be able to follow that ramping over time.

Minimum load refers to low-load periods

when there's excess generation. The question is what to do with that generation, to curtail it, or to try to export some of that to neighboring areas.

That issue can be exacerbated by certain types of intermittent resources. That's an issue that's occurring now; needs to be addressed looking forward in terms of the types of controllable generation that we keep online at various times.

Reserves and ramping has two parts. One part is the reserve requirement that's set by WECC rules. The other principal issue is how you count intermittent resources in the forecast that set your reserve requirements. The second is, again, an issue about controllable generation and how fast you have to be able to ramp them, how much you need, how fast they can ramp in order to keep the lights on on a continuous basis.

Underlying many of these issues, of course, is this issue about forecasting accuracy and our ability to forecast how much intermittent resources available at what time of day. And how that forecast interacts with variability in the load forecast. It's going to be a key issue in terms of the correlation or lack of correlation in those forecasts in terms of the scheduling for both of these issues, for all three of the above issues.

Those issues will all explore quantitatively in our initial analysis; that's work that has continued in the intermittency analysis project. I'll talk about some of those later on in your process.

There are a number of issues we also looked at qualitatively. Storage is a critical strategic resource for trying to balance the difference between when intermittent resources generate and what the load and generation balance is within the ISO.

And by stored we're taking a very broad view, looking both at traditional hydro, pump storage, which is a critical strategic asset, as well as pumping loads from DWR and the pounds associated with those loads and the schedule ability of those.

Frequency and voltage requirements refer to reliability rules. The voltage ones are largely being addressed in the WECC's low voltage ride through capability. There is a larger issue about frequency, which is a bigger issue than renewables, per se, but it's about declining frequency response in the west. And the challenge it's going to be to be able to operate a system reliably going forward in the future with more renewables. And the needs for more demands on the controllable generation that you have to do that frequency response.

Resource deliverability refers to being able to deliver the load -- the resources at all times. Here the challenge is almost a methodological one in which most studies consider principally peak demand conditions, and there's a need to look at deliverability issues at offpeak times when transmission constraints might be more binding.

The import capability goes right back to this minimum load issue, as well as the deliverability. And it goes to the issue of can we export some of the generation at minimum load times; what are the limits on bringing that load into the state at other times.

And, again, it's about -- then there's a separate issue from the operational standpoint about larger issues in the west about whether we're able to maintain the path rings that set the amounts of imports or exports that we can have in and out of the state at various times.

I think I spoke in the planning and modeling, but again I think the issue here is looking at the ways in which the introduction of renewable generation might be key to change the assumptions that we look at when we conduct those planning and modeling studies.

What we then did, having identified these issues and trying to characterize them specifically in the context of the challenges that California faces, is bracket them into four high-priority policy issue areas.

One on defining the attribute requirements on a control areawide basis of what we actually need. Two is the number of issues toward reducing uncertainty; I talked about it in the context of load forecasts. There's a number of other areas that plays into. The third is resource policies and improved planning and modeling.

Our project really is focusing on selected aspects of the first three of these. And I'll talk about what those are specifically.

In the area of defining attribute requirements, I think there's a clear understanding from the operational issues that we've identified, that there are questions about how much control of generation needs to be available, at what time of year and what quantities, and with what capabilities.

And so our focus there is defining what are those requirements. How much do we need? How much ramping do we need? How much -- what are our minimum load issues? How frequently do they occur? And really to try to develop metrics around them so that we can measure progress in trying to address these issues through a variety of either physical, contractual, regulatory or market means in terms of achieving these integration objectives.

This is a key part of our project. And so I want to distinguish -- we also want to focus on resource uncertainty. And the principal area that were going to be focusing on is looking at some of the wind forecasting. Now, and this is an important difference. We're not so much focused on what is the best wind forecasting methodology. There's other PIER research that's supporting that objective.

But really what are the metrics that are used to measure how well you're forecasting load, as well as wind. And what is the performance over the time, and what are the performance that you need over time in order to be more able to more appropriately integrate these resources in view of the uncertainty you have.

So I would distinguish our project sort of in a broad sense from conducting novel research about new technologies to integrate intermittent resources resources generally speaking; but more about the processes by which this integration process is going to take place.

And specifically from a management and policy perspective, how we're going to measure the dimensions of that performance that need our grid to have and be able to track progress toward those objectives over time.

This is sort of the ground level pragmatic. How do we get from here to there, as opposed to what would it look like if we had everything that we wanted.

ASSOCIATE MEMBER GEESMAN: Joe, in terms of uncertainty, is there a comparable metric offered on the load side? In terms of trying to bound the variability of load and considering some of these intermittent resources, in essence, negative load?

MR. ETO: Absolutely. And I think the point here is there's uncertainty in the load forecast and there's uncertainty in the resource forecast. And there's also correlations between those uncertainties, or lacks of correlation.

And all of those need to be accounted for simultaneously if we're going to figure out what the net effect on the operational requirements of the remaining generation that's going to have to make up the difference here.

And so those things need to be considered jointly in some sense if we're going to make progress in this integration issue.

Another area that we're going to focus on in the resource policy area really is looking at, again, this question of storage. That is a critical strategic resource for the integration of renewable resources in this state.

And by that I mean a very broad net, looking at all the variety of types of storage that are available to the system and what is physically possible. I don't think we fully understand that yet. And given what is physically possible, what is the reality today of how these things are being operated as a result of historic contractual, environmental, legal or commercial agreements.

And what we ought to do to revisit some of those, to achieve a much more smoother and holistic approach to integrating them into a system approach to try and look at this issue of renewable integration. And we're not focusing on planning in -- so I'm going to bypass going over those issues right now in the interest of time.

So let me talk about what we're focused on specifically this year. I think a key point for our work this year is to coordinate with the intermittency analysis project, which is in the final stages of its work.

This has been a very detailed analytical study of what the system might look like in the future. And sometimes provides targets of operability, what we're going to have to deal with to operate to. And these, in turn, identify some of the metrics that we might use in learning where are we today, where do we need to be in the future.

These will translate directly into things like control area resource attribute requirements; about what we need from dispatchable generation. You know, our vision might be, for example, to work with folks at the ISO as the control operator. They're obviously a key partner with us in this research activity, since they are the ones where the buck is going to stop in terms of these operational issues.

Work with them with their data, with their processes to begin to identify what it is they're going to need from a resource integration perspective, from a system operability perspective, and be able to articulate those in a very clear and succinct manner so that those who are in the market, be it load-serving, the IOUs, can bring those types of resources to the IOU, to the various market and other procurement mechanisms that are available to them.

So, again, what are those resources attributes; what are exactly the metrics that underlie where we are today, where we need to be in the future. These will be things like what are the number of minimum load hours; what is the type of ramping that require; how much dispatchability do we have of our current fleet of generation; how much is physically possible; how far away are we from that.

We hope to begin gathering that information, assembling it into metrics that can be used essentially to track that progress about where we are today and where we need to be for more seamless integration of these resources.

And, again, I can't emphasize enough how much these hydro and pump storage facilities, as well as these pumping facilities of DWR, have been critical for taking -- for stepping back from historic relationships, historic contracts, historic operating procedures and reevaluating in the context of needing to now accommodate a very very different type of resource going forward into our power system.

And looking again here, and this is very critical, the difference between what is physically possible, in which we think there's lots of opportunity, versus what is currently the case, in which we have to revisit these agreements and see to what extent they can be changed. Who needs to be involved; what is it worth to them;

and who needs to pay for those sorts of things.

We are really at the beginning of our process, so our focus has really been on coordination and collaboration with the various stakeholder groups that are out there, involved in a number of workshops. We've been actively involved in the analysis project activities.

In my next slide I'll talk about some of the finds that are emerging from that that directly relate to some of the work that we'll be doing this year.

We are actively engaged in discussions with the ISO. You know, as I've said before, they, as the control area operators, are the key folks who are going to need to be able to articulate some of these requirements; who are going to take responsibility for coordinating with the various parties that need to bring these types of characteristics and attributes to the system in order to be able to operate it.

Of course, the Western Electricity Coordinating Council plays a very important role. They have begun some nascent efforts in this area, essentially to write a whitepaper on these topics. And we're communicating with them regularly on that basis.

There is a large project sponsored by PIER, the intermittency analysis project. They held a workshop here at the CEC a couple months ago. And they've done a lot of analytical work that bears directly on the types of work that we'll be looking at in this study.

In the area of load following they found an increase of about 7 percent in general; and much larger during light load periods. Very consistent with our earlier findings.

They're finding that the periods of the light loads will increase the minimum load problem; it'll increase the frequency; and may, in fact, require curtailment at various times because of over-generation.

There are obviously opportunities to, you know, modify the way the generators operate. And those are some of the kinds of issues we need to explore. Again, one of the things I'd like to distinguish is this IEP study is a study of the world that could be, based on assumptions about resources that are available, and assumptions about their physical properties and capabilities.

Ours is a study about, you know, given

that potential where are we today; what do we need to do to move toward that objective to the extent that those differences are manifest not in physical limitations, but in contractual and other types of restrictions.

I'd also like to caveat these comments here, that these are preliminary findings that were presented by the IEP project. I know they're in deep discussions with the ISO to get new data to improve that analysis before they finalize the report. I believe that qualitatively these findings will hold in terms of the implications of the type of work that we'll be conducting this year.

Reserves and ramping, very similar findings in terms of, you know, increased stress or depletion of some of these reserves under certain conditions. Absolutely increases in load volume and regulation requirements.

Certainly the forecast variability and the need to be able to look at those forecasting accuracy issues in the context of these integration questions. Very important.

And I think very key, again, the storage plays a key role. And the analytical results are bearing this out. And, again, to a limited extent, also find transmission upgrades and system enhancements might be needed to support pumping during the minimum load hours.

So, again, very consistent findings in terms of what could be, what is physically possible. But, again, the reality today is that these problems are severe and that in order to realize those objectives we're going to need to track progress in moving things toward that more ideal state.

So where we plan to go next is the IEP report will be final very shortly. We are under explicit agreement to try and modify our statement based on the final analytical findings there. Of course, there's a tremendous amount of engagement, both with the ISO and the utilities, particularly to gather the data to begin developing these metrics; to begin establishing some baselines; to begin talking with them about some of the operational requirements and constraints that currently prevent us from operating the system the may we might want it to operate, were we able to take a holistic view of integrating renewables.

Our final report will address all these

issues, starting with the formulation of some of the metrics that should be monitored and tracked. We think that in a number of areas data will be available to support our developing some baselines so that a tracking process can continue.

Some of the outstanding issues that would have to be addressed, we'll try to identify them to the extent they're not already being addressed by other activities.

And, of course, policy recommendations about how to maintain this process. And that we view ourselves as trying to jump start a monitoring and tracking process. There will be issues that will have to be addressed going forward about who is going to maintain and sustain that activity going forward, as we achieve these goals. And that's where the research will end and the work will begin.

Our final report is targeted for December '07. And with that, I'm going to conclude my prepared remarks. Thank you.

PRESIDING MEMBER PFANNENSTIEL: Thank you. Questions from the dais? Questions in the room? Yes.

MR. TOKA: My name is Charles Toka. I'm

with the Utility Savings and Refund, a private company. We're also sales affiliates for VRB Power Systems; makes a large flow battery.

And I wanted to ask Joe, a lot of the issues you raised here on the integration issues are addressed by advanced energy storage products. And I know that the CEC has done a lot of research on these kinds of flow batteries, other kinds of battery technologies. Placing these at the windfarm would solve all these problems. And you mentioned storage being a very important issue.

What are the plans, what plans do you have for integrating these kinds of technologies in your report, and for including them as potential solutions for the problems for renewables?

MR. ETO: Our task -- well, let me make two different comments. One, I think storage, as I've said several times, a very important role to play in integrating renewable resources into the operation of the power system.

Our report, however, is not really a focus on so much solutions, as much as it is on performance requirements. How those requirements are met may be through a variety of means. I think storage will play an important role in what type of storage, who owns it, where is it placed. That's really not the scope of what we're focused on in terms of choosing what technologies should do the job.

We're really focused more from a system perspective of what it is you need to be able to operate the grid reliably in the presence of a significant contribution from renewable resources.

PRESIDING MEMBER PFANNENSTIEL: Thank you. Other questions? Do we have anybody on the phone or --

MR. NAJARIAN: We do not have any Webex participants requesting questions at this time.

PRESIDING MEMBER PFANNENSTIEL: Thank you. Chuck, I'm going to suggest, since it's late, and since the next presentation looks fairly meaty, that if it's okay with Mohamed that we put that until after lunch. If he needs to go before lunch, then we can do that.

So, then I'd suggest that we break now for lunch, and then come back and pick up where we are.

MR. NAJARIAN: Okay.

PRESIDING MEMBER PFANNENSTIEL: Does

that work?

MR. NAJARIAN: Yes.

PRESIDING MEMBER PFANNENSTIEL: We'll take one hour for lunch; back at 1:15.

MR. NAJARIAN: Okay, thank you.

(Whereupon, at 12:17 p.m., the workshop was adjourned, to reconvene at 1:15 p.m., this same day.)

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AFTERNOON SESSION

1:20 p.m.

PRESIDING MEMBER PFANNENSTIEL: We're about five minutes late, or maybe like an hour and five minutes late from where we're supposed to be at this time.

So, Chuck, why don't I hand it back off to you.

MR. NAJARIAN: Okay. Thank you. At this time we're on item number 5 in our agenda, addressing regulatory barriers. And our first speaker in this regard is Mohamed El-Gassier. He's with Rumla. He'll be talking about network benefits of renewables. Mohamed.

MR. EL-GASSIER: Good afternoon, Commissioners and staff. I'm tempted to imitate that Russian accent when I tell you that I came through nine time zones to be here.

(Laughter.)

MR. EL-GASSIER: And also to warn you I'm a little bit slow today. And for this reason, rather than going through my presentation first and give you the point that I have to make, I'll start with that; tell you what you're going to get out of it while your attention is at peak.

There is, I'm told the FERC is about to decide, I think after tomorrow's decision's going to come out, right? On the third category transmission.

And I can't over-emphasize how important it is that the decision and that initiative for all consumers in California; and in fact, in the entire western markets.

And there's only three ways FERC's decision is going to fall. Either in a strong endorsement, a yes, a strong yes; or a rejection because of some maybe legal arguments embedded in the Federal Power Act; or somewhere in between.

Now, if it is an endorsement or even conditional endorsement, I have a plan A for you here of how you can push the envelope and gets while you work on the tariff, which will be the next phase.

If it is a no then we have a plan B of how you go back and go about enforcing this measure which I think the only state that enjoys it, or a form of it, the third category of transmission is Texas. Texas happens to be independent of FERC's jurisdiction.

And there is a plan C, but I'm not going to talk about it publicly.

So, on with the presentation. We've got a full agenda here, but I'm going to go fast through some items, some pages. And if you need details you can find them in the report which is posted by the CEC. And you can get a reference to it later on.

The background of this issue was the Edison's proposal to establish trunk lines; and unfortunately the name trunk line got stuck with it. And I'll tell you why it's unfortunate later on.

So they were very creative, Edison, and made a very interesting proposal and said, they take the credit for being the first to do that, said, look, you know, we got this Tehachapi investment; we've been struggling with it for years and years and years. And we're in this chicken-and-egg problem; we can't get financing for it.

And for a number of reasons well known to most of you, I can summarize them in the next slide here. So, FERC said, well, look, you know, trunk lines are radial investments. And radial projects mean no network benefits. Since they don't offer network or reliability benefits, means this is something we will consider as a direct assignment cost recovery; generators have to pay for it.

And very importantly, and I think it was in a couple of opinions, dissenting opinion or comments by a couple of Commissions -- and they said, well, there was no showing of system benefits. And that's what caught my attention and started this effort.

The opponents, and I have to say they're really misguided, and I think I can prove it, they said, well, trunk lines are generation ties to be paid by the sponsor. There is also fear of setting a precedent. If they open the door, and these are mostly municipal utilities and co-ops, and they pay the transmission access charge. So, you know, we open this door, there's no end to it.

And then there is the third thing which is in long-term problems, this thing invites CAISO and encroachment on generation planning. And there's really a lot of truth in that. And that's going to be a problem right away.

So, what are the attributes of third-category transmission. We will call it that way rather than trunk lines.

Well, there are about four things you can talk about in general, and then we go into detail. They can make up for the inadequacies of the traditional transmission investment financing. And they can make up for market failures. They also facilitate the RPS implementation; I would say efficient implementation. Without them you can't do it, you can't do RPS in an efficient manner.

And then renewables, above all, represent economic and strategic investments. The Legislature saw to it and passed a couple of laws on that.

Now, with respect to these inadequacies traditional mechanism. First of all, this initiative will accommodate locationally constrained resources. It's also able to accommodate low density renewable energy; and I would underline low density because that's been absent from the discussions. And I hope it will not be absent from the discussions that will lead to the design of the tariff, assuming FERC will approve it. Then finally, as I said, it can lead to efficient implementation of the RPS.

Now, the low resource density, and this is especially true for wind and solar, and less true for geothermal, those geothermal shares that you have a resource disaggregation. Not always this is an advantage, and it should not be distorted by unwise schemes.

You have a resource that's already disaggregated; it lends itself to competition on the generation or the developer's side.

You've got this economy of scale for the first investors, you know, the problem of distance and the problem of size. Then you have the investors' self organization which doesn't seem to be easy to do, and there's no proof than the Tehachapi which I think about 15 or 17 years or so, and nobody was able to bring these cats together, herd them into a project.

So, why we say it will lead to efficient RPS implementation. First of all, we think it is necessary to plan the investment efficiently. These are, after all, are going to be large projects. And they're not trunk lines, they're going to be more of the form of arteries, branches and sub-branches.

It will provide greater access to

resources. So would provide you with the opportunity to actually do some optimization even at the state level, at the CEC level in particular.

It will promote competition between the developers. The more resources you have access to, the more -- I mean you talk about one of the essential conditions of competition, which is that the product has to be divisible, or can be small, can be divided. So it lends itself to modularity. And that's why you see projects as little as 20 megawatt, 50 megawatt. The largest probably about 150 or so.

Reduces also the renewable energy certificate program risks. There are debate at the Center at the CPUC on that subject. I think if you -- if FERC approves that and you successfully implement the third category, transmission, cost recovery mechanism, then you will have lower risks. I'll talk a little bit more about that low risk associated with direct program.

The renewables represents strategic and economic investments. We know about the strategic environmental values, both local and global. And there is some issues there, as well.

Also there's an economic return. And that's the one I'm going to talk about most of the rest of my talk. Reliability and fuel price moderation would fuel diversity.

We did some assessment of that, but the one we really focused on is the second one, the electric energy price moderation.

Now, the electric energy price moderation, there are three things about it. First, it's a real benefit for third parties. Not just the sponsors of the project, but also everybody else.

It is demonstrable. You can demonstrate for regulatory proceedings. And it is also a likely criterion for prioritizing these projects. When the time comes and you have a whole bunch of areas you have to consider, I will propose that one of the criteria you use is how much does it contribute to moderating the electric energy price in this market, in this centralized market that we have.

So, the demonstration approach, we tried that and we were successful actually. And this is the project that we did here for the CEC. Now, to address this transmission conundrum, you got the problems of resources, how we deal with it, multiplicity investors, location flexibility, transmission investment barriers, and the one in blue, and very very important one, is the free rider problem, which nobody has spoken about at all i the debate that I have seen so far.

Now, so what I said, well, lets focus on the benefits of the non-sponsoring parties who seems to be the ones who are opposing this effort from the beginning, from the get-go.

And we will show them that maybe they are in error what they're doing. And maintain simplicity by doing that. So, I made a number of assumptions. I'm not going to go through them. They are explained in the report.

The idea, when you do these kind of projects, avoid complex modeling because, you know, the message gets lost in the arguments about, you know, all these kind of assumptions.

So we made a whole bunch of assumptions, about ten of them, to simplify. And most of them, I would submit to you, and in fact, the totality of these assumptions will clearly lead to the under-estimation of the benefits that we're trying to reach. That's the market electrical price moderation benefit.

What's going to set prices in the market is the ISO LMPs, location marginal prices. Not only in the short run, but will be the basis upon which contracts would be negotiated from here, you know, onwards.

And if you look at that, it has three components. The energy commodity price, the ACP, the marginal loses, and the congestion. And for reasons that I don't want to get into the details, we'll say well we can ignore the marginal losses and we can ignore the congestion. They require something called security constraint economic -- model, very tedious and very controversial to apply.

So if we strip it from these we get to arrive to the heart of the issue, which is the energy commodity price. What's interesting about it, it is totally fungible. And I remember Commissioner Fesler was asking a very critical question before he made that fateful decision to go ahead with that market design, he said, anybody can tell me whether electricity prices, wholesale prices, are fungible or not. And nobody answered.

There was dead silence.

And it turns out that the answer is generally speaking, no, it's not fungible. But if you break it down into these components and concentrate on the electricity, yes, it is.

And one of the main advantages of having the market that we have today, notwithstanding the other problems, but a big advantage to that, there's a single market maker, there's a single price. And that price is the same everywhere, every five minutes, every ten minutes and every hour in the hour-ahead market, every hour in the day-ahead market. It's the same price. It applies to everybody.

And it's the one that drives all kinds of things. Now, congestion and the marginal cost components, they depend on it; and they are highly localized. And there are ways of mitigating it. One of them is the new concept of the renewable energy certificate, by the way.

So, what is this fuel cost component, because that's the main part of this electricity energy commodity price, is the fuel cost component. There's a markup. We can ignore it because normally the fuel cost component is about an order of magnitude higher than the markup component.

And so as I said, the effect of all of these assumptions predominately in the direction of underestimating the benefits to nonsponsors. And what does a couple of lawyers, a couple consultants who work with the municipals, I wish, I hope they listen and listen very carefully to what I'm going to say here.

We don't need to run a SCED, or security constrained economic dispatch model. And we can also do all kinds of risk analysis tools, but that's not the time to talk about it.

So what we did, what we talking about, if you stack the ISO's -- the resources in California available to the ISO, you stack them in order of increasing incremental heat rate, you get this diagram that you see here.

Okay, and that diagram, wherever it intersects with the load, which happens to be the peak demand for the year 2012, you get the heat rate, incremental heat rate. And that heat rate multiplied by the gas price, or a proxy for that, you get the price signal. You get the energy component of the electricity price. It happens to be about 52 gigawatts; and the heat rate, you can see the incremental heat rate during that time is about 12,000 Btus.

Now, this is for all the loads in the resources for that particular point in time. Now, if you take the wind out of it, what you have, you have a different intersection point. It's the same load, but the heat rate increases by about 900 Btus per kilowatt hour. And that is what we're talking about.

If you have access to these resources, which by the way, they are going to be price takers, because they're not going to bid when is generating, and they'll just take whatever prices. The scheduling coordinator will do what we call sub-scheduling.

So, that's the price. That's the incremental heat rate. And simply the difference between these two times the fuel -- what the system benefits is. It's the system benefit.

But you need the network to deliver the system benefit, therefore it is a network benefit. And that's what FERC was asking about when it refused Edison's petition.

And unfortunately, although it's a very

very good application, the petition that the ISO has put together, it was not aggressive enough about this point. And that's what I call is plan B. We can go back and say, listen, you know, I don't know if the ISO is going to go back if they get the refusal, but we do have an argument that says we're in a very bad situation here. We have a very volatile market fuel prices. We got a needle type demand; we can get stung very easily, especially in location marginal prices.

And therefore we need these resources. It makes sense. And that's why it makes sense for the municipals, for the co-ops, for the government agencies, for everybody; everybody benefits from this globalization of energy commodity component of the LMP.

How we did that, how we just did a load frequency distribution in the loads we got from the probability weights; and we applied that for all along, under the -- came up with some estimates. And here's the estimates.

This is using the Tehachapi segment 3 as a test case. Assuming that the incremental wind generation, 3500 megawatts -- and I really don't know what it is, until this time, I have no idea what is segment 3 is really contributing.

So what I did, I said that's fine. Let's just assume different percentages. So we have here on this side here the minimum amount of sustainable generation. That is what is the generation that you can think you can get out of the wind a hundred percent of the time.

If it is 100 megawatts out of 3500 megawatts, then you're talking about availability or generation capability of about 2.9 percent the time. That's pretty small, okay.

And on and on. If I go 900 then I approach 26 percent. My understanding is somewhere around 30 percent on an average basis. Okay.

So, if you do that, what you get in terms of annual fuel savings, 47 million. That's not counting congestion and marginal loss savings and all these other goodies that come out with it.

But I will say here, I will say conservatively minimum is about $47 million a year; 155 -- and this is the imputed cost of the transmission. Because if this is my annual levelized payment I can calculate then what the cost of the transmission project. Which is interesting, by the way, it gives you an idea about what we're talking here about. This is a $772 million project. I can't afford more than that.

Incidentally, the ISO application before the FERC capped the amount of money that can be allowed as a third category transmission at 15 percent of the net plant investment, total net plant investment in transmission. Which is running right around $4.2 billion at this point. Which means that your cap is about $470 million. Now they can finance a third category project that was worth more than $470 million. And which means in terms of annual payment is about $95 million.

And one of my problems with that is that's too little money. I think you're going to end up needing much more than that.

The thing about it is it's a moving target, so which has interesting implication with respect to if there's going to be a rush to where these projects, different areas, difference people are going to apply to their favorite resource areas. They're going to put it in the pipeline first, because this cap is a cumulative cap. It's a total cap.

Now, I would skip on that. So in terms of possible applications. First of all, this approach would support the day-ahead scheduling of intermittents. Right you cannot schedule your intermittent resource in the day-ahead market, which is a big shame to me. I mean, it's very strange that that's not taken care of. I understand it's on the agenda for what do you call it, like a second generation modification of the MRTU tariff.

If you are a wind generator, or solar, or whatever, you can schedule only in the hour ahead market. I think the tariff that was submitted, I think they relax it a little bit and says you can do it, but the problem is there are no forecasting tools that would allow the generator to safely schedule in the day ahead. And that's why I say it's a shame that's not done, because would require at least two, three years to develop that.

Very important why, because 95 percent of the market will settle in the day-ahead, will not settle in the hour-ahead. And that means if you want to bet the bang from your bucks that you're spending in renewables, you should work on getting it scheduled in the day-ahead; that's where it matters.

Now, so maybe you will say, well, look, you know, maybe your estimates of these benefits are wrong, because this stuff is not going to be settled in the day-ahead, it's going to be settled in the hour-ahead; well, prices are going to, you know, who knows.

And the answer to that is in what the ISO told me. He said, no, you forget about something we call conversion bidding or -- bidding, which is the mechanism that will try to proliferate a difference between, use the difference between the hour-ahead and the day-ahead. I still say you should push for day-ahead scheduling.

It can be used to support in re-petitioning FERC if there is a need to do so; and that's what I meant by plan B. If there is a refusal or FERC says go back to the drawing board, you didn't do it right, we need more, you can reinforce your arguments with that.

Now, then you could use this -- approach or some SCED modeling and support the tariff filing fees. And very importantly to do screening and prioritize competing third-category transmission projects.

You're going to have a bunch of them coming at you, and you need some kind of a tie-breaker or a ranking mechanism that is neutral to all ratepayers; it affects all ratepayers the same way. And you can do that on the basis of the energy component analysis. What impact would it have.

I think it would facilitate also deliberation of the strategic policies development and would be developing. And will also have an influence on developing the rules of -- am I saying it right? REC, R-E-Cs? Okay.

So let's move on to that one, and that's my last slide. Let's assume that the FERC will approve it, and I think I'm leaning that it will approve it with some kind of conditions. I'm pretty sure that's probably where it will go. At least I know one Commissioner, John Wellingham, he would certainly not opposed it and will campaign for it.

Then what you have. You have three state agencies. And these are just thoughts, quick thoughts on how these things go. I think the action will probably start right here at the CEC in terms of identifying these areas and ranking them.

And so the ISO will then, when a bunch of people approach the ISO and they're asked particular area versus another, they can rely on the CEC's mapping or assessment. And it can be a rough preliminary assessment. They'll do the work in terms of evaluating all the system impact studies, et cetera. And there is the problem will they do economic analysis or not, and who should be doing it.

But then the action eventually will move on to the CPUC. And the CPUC will have to think about to allow the investor-owned utilities to participate in this project. There is really a big issue which was raised by Ed Kazlet, the Member of the Board. He's the guy who asks good questions, on the ISO Board.

He said, well, what happens if you have too many of these projects coming in and none of them, they'll all need the first cut, which is to have 30 percent, 25 percent, 30 percent contracts. That's a condition that the ISO's saying that they want; they want these projects subscribed at least

30 percent.

And then there's a promise of another 30 percent will be coming, that's the second condition that the ISO has required. But it never materializes. So you have two, three projects started out, and ratepayers are paying for them. And then they never fulfill their promise.

So the ratepayer funding will continue for a long long time. What do you do about that. And the answer was not clear because that's where the devil lies, you know, in the details. And the tariff and in the cooperation between the CEC, the CAISO and the CPUC.

With respect to the commoditization of the R-E-Cs, the RECs, again I'll tell you there is a -- you know, there is a common universality between the two, between the energy component of the LMPs and between certain characteristics of the RECs. If the RECs are related to global emissions it doesn't matter, you know, you're cutting pollution, you're cutting greenhouse gases, it works for everybody.

But if you're talking about stuff that has to do with local morbidity or health issues then it's a different story. The important thing is the more resources you have developed efficiently the less important is the role of the RECs. You have less risk, less risk of having to use them.

There will be more resources available for all these co-ops, municipals and energy service providers to get their -- to fulfill their requirements under the law.

The other thing is very important. There will be a day where the mandated RPS programs have done their job and we have economy of scale, we have very good technology, and actually renewable resources can make it on their own. What you want in this case, pave the way for intra-renewable competition. And that's why it's totally, what can I -- it's inconceivable to me that anybody would be opposed to this project.

I was just kind of scratching my head, what's going on. Because it's very simple. We have one electricity price, one commodity electricity price. Everybody goes up and down with that. And you want all these resources in order to hedge yourself, and particularly the small systems who are not very well hedged.

That concludes my talk. Do you have any

questions?

ASSOCIATE MEMBER GEESMAN: Mohamed, I think it was your third slide, pointed to some concern on the part of opponents that Cal-ISO would be encroaching on generation planning. I wonder if you could expand on that argument and why some think that would be a bad idea.

MR. EL-GASSIER: Well, I mean in terms of being practical, the ISO does not have the resources to do that, or the mandate to do that. I mean, it does cover 75 percent of the marketplace, but resource planning is done usually by those who are paying for the generation, or those who have a lot greater mandate to do that kind of resource planning.

This is an issue that I think Dede Hapner is here, we've been talking about that since 1995, 1996. The idea is that the ISO would only operate the grids on a day-to-day basis. And do reliability, maintain reliability at the lowest cost possible.

It's mandate is not long-term planning, forecasting. And I have seen them actually try to avoid that as much as possible. They don't like to give you idea about where the market is going.

There is something inherent about that and running the market at the same time.

ASSOCIATE MEMBER GEESMAN: Thank you.

MR. EL-GASSIER: Any question else?

PRESIDING MEMBER PFANNENSTIEL: Go ahead, yes, please.

MS. RADER: Hi, Nancy Rader of the California Wind Energy Association. We had also urged the ISO to make the argument that this would be a network investment, rather than a third category.

And I wonder, since you're making the argument basically this is a network asset based on economic evaluation, why wouldn't you just call it -- why wouldn't you just categorize it in a traditional network category? Why give it the third category label?

MR. EL-GASSIER: Well, because of the Federal Power Act and its nature. Federal Power Act deals with looped networks. This is not going to be looped. I forgot what it is, FERC order 888 is actually has certain criteria.

You're asking FERC to backtrack on what is, their own definitions of what a network is. It will be easier if it is identified as a third category, and stay away from the trunk line, because what you really basically talking about is creating a network for generators, which is something we didn't have to deal with in the past, because we didn't have a need to go after these low density resources.

So, it's better to identify things by their proper classification and not swim against the tide when you're dealing with the FERC. You're getting into issues that it's easier -- look, the objective here is to facilitate the financing and cross the hurdles, to take away that financing barrier against these smaller producers and these projects. How you get about it is almost secondary.

PRESIDING MEMBER PFANNENSTIEL: Yes.

MR. BRAUN: Hi; Tony Braun on behalf of the California Municipal Utilities Association. I certainly don't have any comments right now on the analysis because I just saw it for the first time.

But, I think a clarification is needed. It started from the proposition that there were a host of opponents to the third-category filing. In fact, CMUA did not oppose the third-category filing.

CMUA actually said we do not oppose a deviation from the transmission policy that FERC has had for decades; but we thought that there were implementation issues that needed to be resolved.

And we worked very hard with the ISO and some of the ISO Staff that are here today to work through those things. Some of them were resolved. We had a few outstanding remaining issues, and we actually urged FERC to establish a settlement proceeding to resolve them.

So the starting premise that this is a needed analysis because there were opponents is, I think, requires clarification.

MR. EL-GASSIER: Thank you, Tony, for clarifying that. Your comments actually made me remember something else. I said there's plan A and B.

Now, plan B, if FERC refuse, you just have to go back again. Somebody from the state has to go back to the FERC.

Plan A, what if they say yes. Even if they say a resounding yes with no conditions on it. There's still this tricky issue of taking that label trunk line out of it, and talk about really a network for generators. Because I can promise you that's what you will be dealing with; you'll be dealing with -- it's like those veins in a leaf. In order to facilitate participation by the smaller investors, which is very very important, it's important to be careful about the language as you craft it in the tariff. To expand it a little bit more.

So, that's what I meant by pushing the envelope. And there are ideas we can talk about that, have other ideas as well, related to that.

PRESIDING MEMBER PFANNENSTIEL: Thank you, Mohamed.

Chuck, we have another presentation on this topic?

MR. NAJARIAN: We do. We have a very short presentation by ISO regarding the status of the third category filing. So with that, let's go ahead and move in that direction. Gary.

MR. DeSHAZO: Okay, back again. I was asked to just provide a very short briefing on what ISO's doing with its declaratory order for this third type of transmission.

And just a brief status. The issue in terms of why we're proposing this was that -- and

I think what just got mentioned, is the fact of the FERC's long-standing policy that offers only two approaches in order to, you know, for transmission. One is related to network and the facilities that are rolled into TAC. And the tieline facilities that are paid for by the power plant owners.

The interconnection policies I guess in terms of what's coming in with the renewables is making this kind of a hurdle, is really producing a barrier that is extraordinarily expensive.

Typically in the way that we have couched this issue is that there are what's called nontransportable power sources located in areas that are typically not adjacent to existing transmission facilities. So in order, much like which is what Tehachapi represents, in order to be able to gain access to those, then there clearly is required some transmission investment in order to make that work.

And that the costs that are, you know, proposed by that, I think, sort of set a burden out there for a lot of these small developers who just simply cannot finance the kin of transmission infrastructure that's required to make that work.

What the ISO has proposed then is sort of a third type of transmission category that would, if met certain types of criteria, then would allow for the development of the transmission infrastructure to connect these resources. And then in turn, then that would then be placed in the TAC with the benefits then of connecting to the renewables and going to the ratepayers of the system.

And we believe clearly that in order to, you know, by providing this opportunity, that what comes with that is that if you build it we'll come kind of thing, is that we provide that, sort of remove that hurdle then that will then be a step towards allowing and hopefully initiating creation of renewable resources.

In terms of where we've gone, is that the ISO Board approved the proposal in October of 2006. And the whole idea of these particular declaratory order is to provide, you know, seeking FERC's opinion and guidance on whether or not they believe that this is something that would be worthwhile.

Clearly if we were looking for a positive response from FERC that once we had that, then we would immediately initiate a stakeholder process to work out these details that some of which were brought up earlier, but the others that the stakeholders have. And then once that was ironed out then we would have a proposal for the ISO Board to consider; which would then result in some type of change in our tariff to accommodate for that.

What's listed here are just in general the eligibility requirement that the ISO has set forth, you know. This is simply a list. I am not the one that necessarily came up with all of these, so if you're looking for reasonings for why these are, we probably need to get some other folks involved. I don't necessarily have that.

But I think that overall these seem to make sense to me. But the key aspect of this is that, you know, well, you're building a single transmission line out to some area, I think what we have said is that that's fine, but in the end what we're looking for is the construction of transmission infrastructure that would benefit overall the integrated grid.

Which means that at some point in time we would be looking to build transmission facilities that meet these particular criteria, but ultimately we would be looking to build additional transmission to actually bring these facilities into the integrated grid.

And it would be for the benefit of the system. And so the idea or the concept is that you may want to build to certain, where certain renewables are located. And then at some point in time we'd build additional transmission that would then connect that back to the grid at some other location. The idea being that in doing that in the future would provide a benefit to the overall grid.

So, in the end we're looking that they would eventually tie back into that. There would certainly be analysis that's associated with that in order to make that happen.

The status is very simple. It's still with FERC. And as far as what I've been told there's no information at least from them about when that is to be necessarily addressed. And I don't know if --

UNIDENTIFIED SPEAKER: Possibly Thursday.

MR. DeSHAZO: Possibly Thursday. Okay.

So -- this week? Thursday, this week. So we may bring this to a close. Thank you; I was not aware of that.

PRESIDING MEMBER PFANNENSTIEL: Thank you, Gary. And thanks for coming and staying here with us, providing that.

Any other questions on this subject, and then we'll move on to, per the agenda, on to the next presentations.

All right, Chuck, who's up next.

MR. NAJARIAN: Thank you. Now we move on to Roman numeral VI of our agenda, federal and state corridor initiatives. We'd like to shuffle this part of the agenda a little bit. We'd like to have Judy Grau go first, and she'll be followed by Scott Powers and Duane Marti of the BLM. Judy.

MS. GRAU: Good afternoon; I'm filling in for Jim Bartridge today, as he's running our Webex for us.

We had transmission forms and instructions adopted at the January 31st business meeting and the responses were due back on March 31st, so we gave all of the transmission-owning load-serving entities two months to respond to our questions.

The slide that I have up right now just has the fourth question of the entire data request. The first three were related to asking about their existing transmission system and their plans for expansion of their existing transmission system, and then finally the potential corridor needs. And this is the specific question with the sub-elements listed here.

And so for those point-to-point electrical needs that they identified in the first three questions we asked them to discuss the potential corridor needs in relation to the following.

First, opportunities to link with the existing federally designated corridors or potential federal corridors identified under section 368 of the Energy Policy Act. And we do have the next couple of speakers to talk more about that section 368 work.

The potential to impact sensitive lands that may not be appropriate locations for energy corridors. A consideration of the Garamendi principles which stress efficient use of existing right-of-way first.

Any work previously done with local

agencies and any geographical areas of sensitivity that may have been identified.

And finally, any other known major issues that have the potential to impact a future corridor designation.

And so this is a list of all of the transmission-owning load-serving entities that responded to us. And we have a couple of notations beside some of them. If there's an asterisk, it means that we -- their lack of response could either be due to the fact that they had no corridor needs, but did not explicitly say so. Or they may have referred us to web links which we have not yet had the time to explore.

So that is the case for PG&E, SMUD and Modesto Irrigation District and Turlock Irrigation District, that they either -- PG&E and SMUD, for example, gave us links to other documents. MID and TID their responses just didn't say whether they had corridor needs. Our assumption is they don't, but we didn't get an explicit answer.

And then not applicable is for those utilities that indicated that they had no future -- either they don't do corridor planning or transmission planning in general. So that is just a brief overview of what we have seen so far.

And today, the next three slides we want to focus a little bit on some of the general responses we received. We're going to leave it to our next workshop on May 14th to actually talk about the specific corridors that folks have recommended. But for now we just want to talk about some of the general things that we heard.

First, is that there is the greatest opportunity lies in extending federally designated corridors on to nonfederal lands in California. This attribution, by the way, is Southern California Edison. And I've noted after each who made the comment.

So they indicated this would streamline the siting process. And they also said that if there are state-designated corridors that don't line up with federal corridors, they are of little value for their proposed projects that must cross both types of land.

Another comment Southern California Edison made was that federal corridors are 3500 feet wide in general, but the SB-1059 language has corridor width of 1500 feet. So they recommended a transition distance of no less than 3000 feet to go from a narrower to wider and wider to narrower, as the case may be, when transitioning between the two types of corridors.

And another recommendation, or response, was that corridors could provide a means to implement environmental mitigation strategies now at a lower cost such as habitat banking.

Some more general responses. San Diego Gas and Electric indicated that the Energy Commission should designate corridors where existing lines are. I believe SB-1059 is for corridors 200 kV and above. However, SDG&E indicated they have 69 kV lines where they meet up with 230 kV lines, and perhaps these would be potential for expansion.

And again they said designation not tied to a specific project, but is in anticipation of future expansion, transfer capability.

Another comment was that corridor designation should also include expansion of existing substations in appropriate locations. And they would like us to identify corridors on a very long-term basis, as long as 50 years.

From the Transmission Agency of Northern California they did not respond specifically to our questions, but the way we laid out the question and the things we asked them to consider they thought were valuable guidance in perhaps selecting potential paths for future projects.

So, in other words it was something to think about, to remind them of the Garamendi principles and areas where they should not go and that sort of thing, as outlined in our question.

And finally, LADWP noted that rapid urban development in the areas of projects could have an impact on corridor designation.

And then we did hear, in addition to the SB-1059 implementation of corridors, just summarizing a little bit of section 368 implementation, we had several parties note again the need for additional corridors across federally owned lands.

And of course, any corridors we designate should be coordinated with the federally designated corridors.

We will be working with the IEPR Committee, of course, and the workshop record that we have been developing and will continue to develop, over the next several months to assemble the Committee draft strategic plan, as Lorraine noted in her slide presentation this morning.

And while we do not want to prejudge what will become a specific recommendation in the strategic plan, we see some potential types of recommendations that could fall out from the forms and instructions responses and other parts of the record.

We may be making general recommendations such as corridors are needed for interconnecting renewables; and/or get more specific in terms of corridors needed to connect specific renewable resource areas to load centers. Or corridors to address growth threats. And, of course, continuity of the federally designated corridors onto state land.

I want to switch topics a little bit. This was not specifically asked in the forms and instructions about rate-based time-extension recommendations. But this continues to be an important issue that needs resolution, or else the investor-owned utilities may not be able to fully benefit from our corridor designation process.

And so the issue of whether a five-year limit for rate basing is sufficient or not was a topic at our March 5th workshop, as you will recall. And so we did hear either -- we went back through the transcripts or through written comments received afterwards; or in the case of the PUC, a document, the last bullet there.

We wanted to sort of compile what we have heard. And so from Southern California Edison they said a minimum 20-year limit would allow them to procure increasingly scarce land at lower costs and with less concern over right-of-way issues and eminent domain proceedings.

From PG&E we heard that the five-year limit is insufficient and we need to review that policy. But they did not give us a specific minimum or maximum we should consider.

Imperial County just had a one-word comment, that it is doubtful that a five-year limit is sufficient. But they did not elaborate further on that.

And then finally, the PUC, in its November 1, 2005 consultant report, again noted a five-year limit is insufficient, although as with the others, they didn't recommend a specific length.

And so when we have our next workshop on May 14th, we have some specific questions. This is sort of an advanced look at what we would like to ask parties to respond to.

First, how should the Energy Commission use these corridor data responses to form recommendations. And are these responses adequate to make recommendations. If not, what other sources of data do we need to consider.

How best can the Energy Commission implement SB-1059 on parties' behalf. And then finally, picking up the ratebase extension question again, what state actions are necessary to address the issue.

And so, with that, if you have any comments? Okay. Thank you.

PRESIDING MEMBER PFANNENSTIEL: Thank you, Judy.

MR. NAJARIAN: At this time I'd like to introduce Scott Powers from the BLM national team. He'll be talking about the sections 368 project and the federal corridors proposed for designation. Scott.

MR. POWERS: Well, thanks. I appreciate the opportunity to be here. I wanted to say for clarification first, I am the BLM Lead for the implementation of section 368, but I represent the interagency management team that's taken on this task, which is comprised of the Department of Energy and the Forest Service and the BLM.

I want to just give a brief overview today on where we're at in the implementation of 369 and see how that might dovetail into 1059.

Specifically Congress directed the Secretaries of Energy, Ag, Interior, Commerce and Defense to consider the designation of energy corridors for a variety of uses on federal lands in 11 contiguous western states.

We're also required to do whatever environmental reviews are necessary to make that happen. And then at the end of this process, designate these corridors into our relevant land use plans.

They gave us 24 months to get this done from the passage of EPACT; means by August of '09 we're -- of '07 we're supposed to have this completed, but we're falling a few months behind. That's a little bit of an ambitious schedule.

Specifically Congress said we needed to find a center line with and list what compatible uses can occur within a corridor. And those decisions have to be carried forward into our land use plans.

As you can see, Congress also said we should take into consideration the impact to the national grid in the west. So that, although corridors are designated for a variety of purposes, electricity transmission is the main driver for 368.

So, you know, why are we even doing this to begin with. We think that at the end of the day if we have a systematic network of westwide energy corridors it's going to give industry something they really haven't had, is some feeling of certainty that they can get permits on federal lands for their linear right-of-way facilities.

Because when we make these decisions and amend these land use plans at the end of the process, we're saying that placement of these facilities on these federal lands is the preferred use for that particular type of area. So they're significant resource allocation decisions. And it will provide some certainty.

And with that we think that will streamline the permitting process because if we do a good enough job in the programmatic EIS that we're doing, we should be able to tier off of that

EIS and merely do an EA that looks at where we site that facility within the corridor. So that should save time and money.

And lastly, the consistency issue, regardless of what BLM or Forest Service office you walk into, if you're addressing one of these westwide corridors you should be playing by the same rules. And that's certainly not the case nowadays.

So how are we going to get this done within the timeframes that Congress told us to operate under. Well, we decided we would do this programmatic EIS. DOE's the lead; BLM's the co-lead; and then Forest Service, Fish and Wildlife Service, Department of Defense, States of California and Wyoming are acting as cooperating agencies.

At the end of this process the director of the BLM will sign a single record of decision which will amend all the affected land use plans that are generated out of this process; and so will the chief of the forest for the Forest Service. That's really unprecedented. BLM's done it once recently with our wind energy EIS, but this is much more substantial.

And then those plan amendments, as I said, will contain those specific elements that Congress told us to consider.

In the 3500-foot issue, for corridor widths, it's just a standard that we're using for the EIS for purposes of analysis. When the plans are actually amended at the end of this process we could elect to go any size lower than that. We just couldn't go higher. But we just established that as kind of a benchmark to work from.

We conducted our scoping meetings in the 11 western states throughout the fall of '05. We received hundreds of proposals and comments. And consultation with both the western governors and the tribes is ongoing.

Since we didn't have anything to really show the public when we started scoping in June of '06 we posted basically a snapshot of where we're at with 368 on our website, and offered public opportunities to review and comment and criticize those if necessary. And we got a lot of feedback. We do maintain this website. It's a good source of information on 368.

I'm going to put this slide in here so you can get a feel for the type of comments that we received during scoping. And if you look at it you'll see some general themes jump out at you.

So this is basically what we received from a host of utilities and developers around the west. So we basically developed an objective for how we look at those comments and turn those into proposed corridor alternatives at the end of the day.

Corridor locations to be developed to provide for westwide transmission and distribution of energy, electricity, oil, natural gas and hydrogen between the supply areas, especially the new supply areas, to the demand areas in the western states.

And we did that using a systematic three-step process that we developed as we went along basically.

Step one was to develop an unrestricted conceptual westwide network of energy transmission paths; again to connect energy supply areas with demand centers. And to provide for the long-distance transmission of energy to meet the objectives of 368 laid out by Congress.

And in this first step we didn't consider land ownership or environmental or regulatory issues.

Step two, we applied some what we thought were obvious screens or no-go areas, if we could make that work. And that's to avoid wilderness areas, military bases, testing and training areas, national parks and monuments, refuges, tribal lands, state and private lands which we have no authority, and important known natural and cultural resources.

And we felt like once we completed step two, you know, the makings of a westwide energy corridor network that focused on compatible federal land, that framework was established.

But the most important step is then we took this information to all of our local field units that could be affected by this. We had them consider these proposed locations against, you know, their management objectives for the area, their decisions that have been made in their existing land use plans.

And we tried our best to insure consistency with those plans, because at the end of this process we want it to work. We want it to be able to withstand challenges that you know we're going to get. And if we can walk through this process and demonstrate the consistency factor with our local land use planning and decisions, we believe we will be successful.

Right now where we're at in the EIS is we're looking at releasing the draft for 90-day public review around the end of June. That's our target. This is what we're looking at right now for corridor locations, proposed corridor locations.

And this map is not on our website right now because this is still a work in progress. But it will be posted as soon as the comment period starts.

This is a map that we just had made up to drop in here, what you'll see in California right now. A lot of constraints. I do want to say that we work very closely with the interagency working group here in California. Basically we defer to them with regards to where we thought the best alignment of corridors might be to what the needs might ultimately be on state and private lands.

So it's been a tremendous help having that group to work with. And they're going to stay engaged in this until the plans are amended;

I'm quite certain of that.

I dropped this slide in because its interesting. It shows the number of miles of new corridors, potentially affected acres and the last column is the miles incorporating existing right-of-ways.

You know, wherever possible we've tried to designate these corridors and areas where there's already an existing linear facility, because it made sense to put it there one time, so if we had an opportunity to expand the width of that right-of-way to designate a corridor, that's what we've done. And I think between 65 and 70 percent of the corridors that we're proposing will align with an existing right-of-way. And in California, the percentage is even higher. It's 690 miles out of 817.

This table also reflects the amount of federal land that might be in any given state. And, you know, California, while it's an enormous state, has not as large a percentage of federal lands as a lot of the other states, like Nevada. Nevada's a key point where all the new supply seems to need to go through to get to the demand areas; it's also 92 percent federal. So that's why you see the miles there for Nevada.

Just some of the ongoing issues. I mentioned our target date for release of the draft is in June. If you access that website you'll automatically be notified, if you choose to select that option, of when the public comment period starts. And you can state how you want to get a copy of that draft, either electronically or CD or hard copy.

We're continuing to struggle with section 7 consultation, but moving forward. Just bringing this many agencies together to try to do this, something this massive, has been unbelievably challenging. Because everybody brings their own agendas and needs to the table, and cultures, as we've described it. And it's just something that none of us who are involved in it have ever been affiliated with.

Again, we anticipate getting the record of decision by the end of the calendar year, which will put us about four months behind. But if we can get it done by then I think we will have done good.

Some contact information. And so, anybody has any questions?

PRESIDING MEMBER PFANNENSTIEL: Thank you, Scott. Are there questions? Thank you for being here.

MR. NAJARIAN: Are there any comments from anybody on the phones at this time?

MR. ROMANOWITZ: -- I have a question.

PRESIDING MEMBER PFANNENSTIEL: Certainly, come forward, please.

MR. ROMANOWITZ: Hal Romanowitz, Oak Creek Energy. Just one quick comment. I think, based on the experience that we've had in planning the high voltage transmission into Tehachapi and interference with the wind turbines, that some things stand out that would be worth taking note of.

The federal corridor at 3500 foot wide is actually quite good because it takes a corridor of at least 2500 feet in order to allow for wind turbines, maybe 3000, to allow for wind turbines and dual transmission line to interface.

And it takes a corridor of at least 2000 feet wide in order to provide for a high energy transfer that is not subject N-1 loss conditions. And it's something, you know, that generally isn't considered until you get down into final stages of planning. But it is very significant.

So, a 1500-foot-wide corridor is kind of useless for high energy transfer.

PRESIDING MEMBER PFANNENSTIEL: Thank you.

MR. NAJARIAN: Okay, at this time I'd like to introduce Duane Marti; he's with the California BLM team. He'll be talking about efforts to coordinate federal and state corridor designation work.

MR. MARTI: Thank you. Madam Chair and other Commissioners, thank you for inviting us to come today and talk.

When BLM talks about renewable energy we break them down into these five categories. And right now here in California on federal land managed by BLM we have 22 producing rights-of-ways involving approximately 3000 turbines producing about 260 megawatts of power.

And these are based in the Tehachapi area; they're in Kern County and San Gorgonio Pass in Riverside.

Currently we have wind applications throughout the state with the exception of northwest up around Arcata and Eureka. And most of these are for additional testing and monitoring using anonometers.

Some of our applicants who've been out on the federal land for two or three years are now ready to come in with applications for turbines. And two projects I can think of right off the bat, we have one down in Palm Springs that's taking some land that was originally used in the early mid-80s for earlier projects. And we took all of the old equipment off and we reopened it.

And Meadowview No. 4 project is coming in there. And they're looking at doing 49 megawatts. And there's an EIR/EIS that's being prepared, and it's out for public review right now, being prepared by BLM and City of Palm Springs.

And then in the Tehachapi area Hal's company, we're working with them, Oak Creek Energy, on some projects that they have there.

Solar. Currently on federal land at BLM there are no producing solar projects. But BLM in California has received approximately 35 applications for solar projects down in the California desert.

And some of the applicants already have

contracts with utilities for solar energy. Sterling Energy System, which has two projects proposed, one in El Centro and one in Barstow, has a contract with Southern Cal Edison initially for 500 megawatts with the process of expanding that project to 850 megawatts.

They have another contract with San Diego Gas and Electric, initially 300 megawatts with the option of expanding to 900 megawatts. And Bright Source Energy, which is the old Lutz folks, have a contract with PG&E to produce at least 500 megawatts.

Biomass, right now we have some projects on federal land that are producing approximately 615 megawatts, and we're trying to expand that out to about 1500 megawatts. We're working with Modoc County up in the northeastern California, northwestern Nevada, at clearing about 6.6 million acres of land of juniper, which we do not want out on the land, that we would be using that as fuel for possible new projects.

Geothermal. We have 22 producing leases; 4100 megawatts of power, if I did my math right. And Lake, Sonoma, Indio, Imperial, Mono and Lassen County, BLM and Forest Service has just approved two new applications for geothermal up in Siskiyou County, both of which would be doing approximately 50 megawatts of power. Unfortunately, both of them are being challenged right now in court and they're on hold.

And we have some potential new projects in Imperial County and Indio. And then we have applications for the small hydroelectric facilities. And, of course, for those FERC would be the lead.

As Scott mentioned, BLM manages their lands for multiple use. And one of the multiple uses that was emphasized by Congress is rights-of-ways for transmission lines, pipelines and energy projects.

And in May of 2001 President Bush issued the National Energy Policy, which very clearly directed the federal agencies that use the federal lands to help the states achieve their RPS and to upgrade and expand existing transmission infrastructure.

And then Scott was just talking about the energy corridor PIS which will be coming out in, as you said, we have an interagency team here. The Energy Commission and the PUC are cooperating with BLM and Forest Service on that.

For BLM lands, a couple thoughts. And this changed radically today as I was sitting doing the morning session. I mean obviously one of the things that we cannot do on the federal lands is we cannot be planning in a vacuum.

We have to be looking beyond the federal lands and saying is what we're doing for proposals, for projects, for transmission lines, have to make sense as to the rest of the state for nonfederal lands.

One of the big things that we really need to do in California, we're doing this now with the two state agencies, is we need to cooperate with them importantly because I'm sitting here today listening to technical terms, at least technical terms to me, like systems peak and integrated reliability issues, preferred system interconnect issues.

BLM does not manage transmission lines. We don't understand transmission lines, so we get totally lost. So we do not know if the applicant comes to us and says, I want to do this project and I would like to hook it into this substation, we don't know if that's a good thing or a bad thing. We definitely have to be looking to the PUC, the CEC and the ISO for that. We definitely need that.

We also need, as we're identifying in our land use plans, areas that we want to develop renewable energy, as we've been hearing many times today, we need to get transmission capability out there.

And one of the things that struck me as I was listening, I know that the federal agencies, both BLM and Forest Service, are in the process statewide of upgrading their plans or doing new plans. And then I heard the ISO was talking about planning; and the CEC is talking about doing plans; and a lot of the counties are looking at plans.

So we have a lot of planning going on in California. And the one thing that struck me, I sure hope we're all getting together and cooperating, and not just doing these plans independent of each other.

And then one of the questions that's very key for us is that when we issue a federal right-of-way to an energy company or a right-of-way for a transmission line, we are basically giving them authority to use federal land for that purpose. We are not taking any position on whether the project is really needed.

And the earlier question and discussion about determination of need, I thought was a very key one. Because our federal right-of-way grant is dependent on the applicant also getting other federal, state and local permits, which in the case of the PUC would be a certificate of public convenience and necessity. And the case here from the CEC would be a certification.

And I had to agree with the comment, is can we possibly move the determination of the need to the front because if the project is not going to be determined to be needed, then why do we want to go through all the analysis.

And then BLM has been working with the groups, the two study groups, one in Tehachapi and one in Imperial. And we were part of those. And if there are other groups we would want to do that, too.

The one kicker is, as I said, Congress directs BLM to manage the federal lands for multiple use. One of the recognized multiple uses are right-of-ways. However, there are about 13 other multiple uses that we have to look at.

And so when we're doing our analysis we're looking at things like the environmental and regulatory reviews. And we start getting into species and cultural and native American, and the military is very important here in California. Because they have a lot of military training routes. They have a lot of research and developments going on. And we have to make sure that if we're putting up transmission lines or wind turbines or something, we're not going to be unnecessarily interfering with them.

DOD agencies are part of our interagency team here in California; and they have been working with us to identify that.

But we need to make sure that if we have an application for an energy right-of-way or a project out there, that it's also compatible with other competing uses in the same area. So that's one of the things that we have to look at. It's both an opportunity and a challenge.

But I think, in closing, it's really important, I think the interagency team that we put together to work on the 368, it's a great model and I'd like to see us carry that forth for both 368 and 1059.

I'll answer any questions.

PRESIDING MEMBER PFANNENSTIEL: Thank you. Are there questions? Thanks for being here.

MR. NAJARIAN: Thank you, Duane. At this time we'd like to move to the panel portion of our agenda.

During this portion of the agenda we are actually going to have three panels. We'll have the utilities come up; then we'll have developers come up; and then we're going to go ahead and have the agencies come up.

And we're asking each one of the panel members to respond to two specific questions that are on the screen now that I referred to earlier in the workshop.

And how we plan to proceed with this is I'll be asking each panelists to provide a brief response to the two questions. I want to encourage comment and debate among the panelists and the dais.

Once we get through the utility presentations we can open it up to questions from people attending the workshop and on Webex. If that makes sense.

So at this time I'll go ahead and introduce the panelists representing the utilities. We have Tom Burhenn, Manager of Regulatory Affairs for Edison. Dave Geier, Vice President Electric Transmission and Distribution for SDG&E.

Dede Hapner, Vice President, FERC and CAISO Relations, PG&E. Randy Howard, Assistant Chief Operating Officer, Power Systems, for LADWP. Juan Sandoval, Assistant Manager of Transmission, Planning, Engineering and Telecommunications for IID. And from SMUD we have Jim Shetler, Assistant General Manager. And then finally, Tony Braun, counsel to CMUA.

So, at this time I'd like to call on Tom Burhenn, Edison, to provide the first response to the two questions posed.

MR. BURHENN: Good afternoon. My name's Tom Burhenn with Southern California Edison. And I've been working on permitting transmission projects starting with the first time we tried to license DPV-2 in 1985.

And so my perspective today is sort of a person who works on transmission permitting day to day, in the trenches. And I want to start out by first saying, thank you to the Public Utilities Commission for its recent streamlining efforts. Again, as someone who's been involved in this process for 22 years, it's the best today that I've ever seen it.

And the implementation of the streamlining process that they put into place working with the utilities as partners has really made a big difference.

Edison has 35 projects that we need to permit, license and construct by 2014. And so we have a big stake in making sure the process works efficiently and effectively.

Today, in response to the questions, because I know we have a lot of people on the panel and we're running a little late on time, rather than answering them specifically, I'd like to talk about five things that I think everybody in this room and the agencies can do to try and improve the process.

The first, as Dave and Rich talked about in their presentation this morning, we think the collaborative process works. We think it's not perfect, but it works pretty well. And we'd like to see continuing collaborative efforts among all parties to try and site the necessary transmission; and to work to improve the collaborative process.

Secondly, we'd like the California Public Utilities Commission to timely approve our advice letter that we just filed, which identifies four areas that Edison would like to study that we believe have a high potential for renewable resources in western Nevada, eastern San Bernardino County, the Salton Sea area, and western Arizona.

Third, we would like the California Energy Commission to continue your work on corridor designation. We think that is crucial.

Fourth, and something that has been touched on a little bit today, and I was encouraged when I heard Scott's presentation just recently, he's right when he says depending on which federal agency and which office you go to, you get a different reception. I want to say uncategorically that our work with BLM has been great and smooth, but I cannot say that about other federal agencies, such as the Forest Service or U.S. Fish and Wildlife Service.

Ah, the mike's not on. Do I need to

start over?

(Laughter.)

MR. BURHENN: My apologies. And then lastly I think there's a role for all of us here today, and especially the agencies, in educating the public and local government agencies about the use of existing corridors.

And that comes in two separate messages. The first is if California's really going to develop a very robust renewables portfolio you need the transmission to get the renewable resource to the load center. A lot of renewable resources do not exist where people live or work. And so the load is distant from the resource areas.

And secondly, I think I'd like to see the agencies and the other parties educate the public that if you live next to a transmission corridor, it's down the block or across the street from you, or ten miles away, you need to understand just as like if you had moved in next to a freeway or an airport, that some day that might expand.

Now, the transmission corridor may not get wider, but if it's not fully utilized the utility may put more facilities in it, or the existing facilities in there may get torn down and something bigger put in their place as Edison and the other utilities try to make maximum use of existing corridors.

Thank you very much; that ends my comments today.

ASSOCIATE MEMBER GEESMAN: The 35 projects that you mentioned, those are the ISO numbers -- they don't all require CPCNs, do they?

MR. BURHENN: Those 35 projects, probably 30 of them will require a CPCN, a permit to construct. Eight of them are for RPS projects, about the other 20 are for load growth. And another seven for associated reasons like economic projects, like DPV2.

ASSOCIATE MEMBER GEESMAN: And have you done a screen how many CPCNs versus how many permits to construct?

MR. BURHENN: Not offhand, but probably about a dozen CPCNs within the next six years.

ASSOCIATE MEMBER GEESMAN: When we had our workshop in early March on the corridor designation legislation SB-1059, your company's representative suggested that at the time a corridor is designated that there should be a determination of purpose and need for that corridor; and that decision should not be second-guessed thereafter. Is that still your position?

MR. BURHENN: Yes, it is.

ASSOCIATE MEMBER GEESMAN: Thank you.

MR. NAJARIAN: All right, let's move on to the next presenter, Dave Geier of SDG&E.

MR. GEIER: Good afternoon, Commissioners. First of all, thank you for allowing us to participate today. This is a very timely and important issue for the state. Also I'd like to thank the CEC for all your efforts to really help move forward this renewable energy goal we have. And also your acknowledgement that we have to build transmission to accommodate and link the renewables to the load centers.

For our case in southern California there's a huge vast amount of solar energy and wind energy in the Imperial Valley. We've been working with our partners at IID on a very important project, the Sunrise project. But from the studies that the CEC and others have completed there is a potential of 13,000 megawatts of renewable energy in the Imperial Valley and east of San Diego.

The other advantage to that is that those resources are diversified. There's solar, there's wind, hopefully there's geothermal, all with their own load patterns. I know one thing that the ISO is very concerned about is how we're going to integrate all this into the grid. And I think that diversity brings a lot to the table.

And that's, you know, one reason that we proposed the Sunrise power link. Most people are very aware of that, and I'd just like to make one correction on some of the comments that Rich made earlier, and the comment about work at Anza Borego State Park.

It goes back a little bit that Dave Olsen mentioned as far as people's involvement in these projects. I think it should be generally understood that as you move into projects people's awareness and their concern raises as you get further into the process and the closer it becomes to reality.

In fact, we embarked on a huge public outreach program from the project in general. We had met multiple times with the State Park Commission, the Commissioners, the state Anza

Borego Foundation. So there is a continued effort and we look forward to working with them in the future, also.

I mentioned the renewables in Imperial Valley. And one thing that's happened since we proposed the Sunrise power link is that there have been 6000 megawatts of renewables in the generation interconnection queue.

And what's interesting about that is that it's all renewables. There's nothing being proposed over that line that is not a renewable resource. So the biggest issue we have is that how do you get the transmission in place to not strand those big potentials of renewable energy resources.

Now, two of your questions you asked today, what are the barriers for transmission; and you know, what action that the stakeholders can do to remove some of these barriers.

Due to the limited time I also have a handout which is on the tables in the back. But we think the number one barrier is the timeliness of getting these projects licensed. It is really something that, you know, we have a current process in place; we believe the PUC process is adequate and works.

And it really comes down to implementation. As some folks mentioned this morning, the CPUC energy division has done a terrific job of streamlining the process. They brought their environmental consultant on early. They've worked with agencies to get them onboard. They worked very collaboratively in all the workshops they've had, all the public outreach.

They've been very visible; they've held workshops for their process; they've held workshops in conjunction with the ISO. So all that's going in the right direction.

And what we're really looking forward to is, you know, getting a decision here in January of '08 on Sunrise. But there still is a lot of work to be accomplished.

For example, as we have this process, one huge challenge is the discovery process. To date we've had over 3500 data requests that we've had to file. And there was discussion this morning about the impacts on resources. And I think we all acknowledge the importance, especially on a case as significant as this, of creating a good solid record.

But that has to be balanced with the fact that this project, you know, needs to be done in a certain timeframe and needs to be completed on a schedule.

So probAbly the number one thing that we see is sort of preserving the schedule of Sunrise and other transmission projects is imperative. Any delay is going to really put a big kink in the ISO and the utility's resource planning.

In our case, the line is being proposed from basically three points of view. From a reliability to connect to renewables, which is what you're talking about today; and then to an economic project, also.

The other thing, if we do not have timely approval and implementation of the existing process, it is also going to impact the developers of the solar energy. A lot of their projects are tied to getting their financing that's tied to the transmission lines. So, we really need those timely decisions.

Probably the most important thing is that we do get connection to these megawatts of renewable energy in Imperial Valley. You know, it just would be a shame, and I think that we all have responsibility to make sure that we can have a process in place that will allow us to tap these megawatts and not leave them stranded in the Valley.

Thank you for your time today.

PRESIDING MEMBER PFANNENSTIEL: Let me just ask one clarifying question. You talk about the improvements in the PUC process. Then is it your conclusion that, in fact, the process is fixed and now it's just a question of working your way through it?

MR. GEIER: I wouldn't go as far as to say it's fixed. I would say it's improved. And, again, I think the key is that we can work through the process and get kind of a timely decision. So I don't think that we can come to the conclusion that the process is fixed yet. There are lots of opportunities still to sort of to get derailed. But I'd say it's very encouraging at this point.

PRESIDING MEMBER PFANNENSTIEL: Are there any specific barriers remaining, or problems or obstacles or something you could point out to us that maybe we could help to improve?

MR. GEIER: Well, probably one thing that you could help is, you know, continue your advocacy working with the other agencies, particularly the state agencies. I think the presentations we just heard from BLM, all those parties have been very good to work with. And it's just a matter now if we can pull it all together. And there's just a tremendous amount of work to do before January of '08.

But I think that's probably the biggest thing that the CEC can continue to do is to work with the other agencies, state and federal, to actually drive these processes to completion.

PRESIDING MEMBER PFANNENSTIEL: Thanks.

ASSOCIATE MEMBER GEESMAN: Just expand on your point and some of the discussion earlier this morning on the Anza Borego situation. I recall, and I don't know, Dave, if you were at the hearing or not, Commissioner Boyd and I in the 2004 IEPR process held a hearing over at the CalEPA auditorium.

And your project was the subject of quite a bit of discussion. The representatives from the State Department of Parks and Recreation sang your company's high praises as to what a pleasure it had been to work with you so early in the planning process. And that they actually saw the line representing an improvement over the existing smaller line that goes through the Park now. And they looked forward to reconfiguration of the existing right-of-way that they saw the new project allowing for.

So, times change. Opinions change Decisions get reviewed higher up and are subject to external pressures and considerations. And, frankly, I'm not close enough to it to know whether the earlier judgment was the proper one, or the later one is the proper one.

But it seems to me that we really need to figure out a way to move some of these threshold decisions earlier in the process, rather than let them all accumulate to one big gladiatorial shoot-out at the very end.

And I don't know obviously what lies in store for the Sunrise project. Certainly this Commission has been supportive of it, and will continue to be so. We're not involved in the siting, so we don't have a viewpoint as to the appropriate route. But we very much think the project is an important one and necessary to California's energy goals.

I'm fearful that the state's process

becomes too focused on whatever the project de jour is. A few years ago it was the Valley Rainbow project. And that was an unpleasant outcome.

Before that it was the Path 15 project. And that was a very unpleasant outcome until it rose again from the ashes after the federal government stepped in.

We went through Jefferson-Martin; and that was a pleasant outcome.

I'm not certain that we're deriving much instruction from the standpoint of process improvement. You got people at each of the agencies trying to collaborate more closely together, and run faster, block harder.

But I think that there are some systemic flaws that we really need to pay pretty close attention to. Not so much to impact the projects in front of us today, as those that are four, five, six years out.

But I certainly wish you well. And your project has a long history of association in favorable consideration by this Commission.

MR. GEIER: Thank you.

MR. NAJARIAN: Okay, why don't we move

on to Dede Hapner, PG&E.

MS. HAPNER: Thank you. Good afternoon, Commissioners. In the interest of time I will also try to specifically answer the questions without too much digression.

In thinking about the questions I thought about workshops like this and conferences that have been organized by many different groups and trade organizations. All of them asking the question about what barriers exist for meeting RPS goals.

And I think the last presentation that I did on this topic, since that time, and I think it's only about a year, several more states across the country, and particularly in the west, now have aggressive RPS goals of their own.

And so I think that the comments that were relevant then were merely prescient for what we have to deal with today.

Over the past couple of years PG&E has developed contracts getting us well on our way to meeting the 20 percent goal without very much in the way of transmission -- new transmission. We've had a series of transmission upgrades. And those have moved through rather well in front of this Commission and also the PUC, with the streamlining that the PUC has put in place.

And also the recognition that reinforcing the grid for reliability and for renewables is a high priority.

What, to me, is a greater hurdle is the fact that we have many more participants in the room. And while that's a good thing, that's a lot more to manage.

One of the issues that typically came up in my comments and those of others were that the competing interests from the state agencies and the federal agencies. And now I think everyone is in the room and moving in the right direction.

It's still very complicated; there are still competing interests as Mr. Marti mentioned. But I think that the process looks much more like our experience for hydro licensing and relicensing where all the participants are in the room very early on, and you can identify some of those fatal flaws in a project before we get too far down a road. So, I find that very positive.

I was very pleased by the presentation that Joe Eto made this morning. And I think it confirms the remarks that the ISO made in terms of the intermittency issues and the system integration issues.

I get a headache thinking of how complicated all of this analysis is. And the more that analysis comes out, the more we can poke holes at the assumptions, the better able we will be to integrate the resources that are going to be coming from many many different parts of the country.

In terms of specific things that would help the process, from PG&E's point of view, again the more public the process is the better. We are constrained, as are other entities, by very strict, appropriately strict, but very strict nonetheless, codes of compliance and rules under order 2004.

So there is not a fluid transfer of information between the transmission side of the house and the procurement side of the house. A public process allows that information to come out in a way that's very useful to all market participants.

Again, brings up issues that might be fatal flaws. And looks at where the resources are, what the transmission needs might be, and what intervenor groups might raise from a much earlier perspective. So I think that's one recommendation we would make.

Another recommendation would be we would like to see the GO-131D process, which has helped quite a bit. We've certainly taken advantage of that streamlined process for projects that are smaller in nature to the extent that the Commission and market participants have seen good results. Expanding that to larger projects would also be very helpful.

Lastly, we would like to see the ISO and market participants contemplate a tariff amendment to clean up the queue. There are a lot of projects that are taking space in the queue that might not be feasible.

And to the extent that we can develop some criteria that will have the most viable ones continue through the process without delay, that would be very helpful. Again, a model that I'm thinking of that's under consideration right now is again on the FERC side, where because of all the projects that have been proposed under the hydro organization for tidal and wind projects, FERC is looking at a more scrupulous analysis and being very specific about the kinds of progress that have to be made so that there isn't site banking, if you will.

So, I think something that looks at the interconnection queue would also be very helpful.

With respect to the question on the corridors, to the extent that the state process can more hand-in-glove with the federal process, that just makes a lot of sense.

Where I think we're a little less enthusiastic, though certainly open, is with respect to specific interconnection options. That may put us in a situation where we inadvertently cut off options. And it becomes more difficult to look at different least-cost opportunities. And, again, just a different kind of hurdle to making it through the process.

So I think I'll stop here and be happy to answer any questions.

ASSOCIATE MEMBER GEESMAN: Do you have a specific queue management proposal?

MS. HAPNER: We've had some conversations about that, and one option would be shortening the amount of time one can stay in the queue from three years to one year or 18 months, something of that sort.

I think it would be worthwhile having a public process to think about some different criteria for measuring progress. And then perhaps we could have a tariff amendment taking that into account.

ASSOCIATE MEMBER GEESMAN: I was pleased to hear your comments about the importance of transparency in a public process. Your FERC exposure clearly is coming through. We don't often hear those kind of comments from your company. And if FERC rules ever allow you to talk to your generation side, you might encourage them to that philosophy --

(Laughter.)

ASSOCIATE MEMBER GEESMAN: I also note --

MS. HAPNER: I had a feeling that's where you were going.

(Laughter.)

ASSOCIATE MEMBER GEESMAN: I also note that the PUC recently provided you with a fairly generous amount of ratepayer dollars --

MS. HAPNER: Yes.

ASSOCIATE MEMBER GEESMAN: -- to go

explore opportunities in the northwest. I wonder if you could elaborate a bit on that.

MS. HAPNER: Yes. Actually, in my effort to be brief I forgot to mention that. I think that's definitely an example of a partnership to try and move forward with renewables; and certainly one worth noting.

It's fairly clear to us that the next iteration of renewables will have to be further afield. And that will take a lot of investigation for a couple of different reasons.

One, just locating the resources, analyzing how real those resources are; and then figuring out the best way to get those resources to our customers.

And the CPUC has allowed cost recovery for that investigation, and a significant amount. And has been working very closely with PG&E to try and look for the best options in British Columbia. It certainly has allowed us to take advantage sooner of some of the planning studies and proposals, knowing that there is that kind of support.

ASSOCIATE MEMBER GEESMAN: You know, I guess I would really highlight that because as we said in, I believe, the 2004 IEPR the State of California has a real interest in strengthening our relations and interconnections with the northwestern states. I think all of the ratepayers in California and I suspect most of the ratepayers in the northwest would benefit by greater inter-regional exchanges.

We used to do a lot more of that than we do now, and I think that California, in particular, suffered as those transactions have diminished in size.

You also look at the northwest wind integration plan published last month. They emphasize, and it's been mentioned several times here today, the importance of geographic diversity in trying to integrate different wind regimes. And some of this intermittency problem may be mitigated to some extent simply by injecting more geographic diversity in the resources we're drawing upon.

The PUC, I think, has been very very generous here, and pretty adventurous. I'd characterize it as the transmission planning equivalent of the Lewis and Clark expedition. And I know you've set yourself a pretty aggressive timetable to show results for that.

It's real important, in my judgment, that you do that because of the unprecedented nature of the ratepayer support, and the fact that, as I'm sure you well know, the state attention spans and state patience are pretty short.

So we hope to see positive results from that on the timeline that you've outlined before.

MS. HAPNER: Thank you. I think we are moving as fast as possible, both on the exploration of the resources and having very fruitful conversations with producers and certainly with the government. And on a parallel, but equally related path, looking for the most feasible transmission options.

And there is a lot of support, as you note, from the other northwestern states, and even a bit further east, because as I say, the times have really changed in terms of the responsibilities that they now have. As well as the recognition that the more players that have strict standards, and some with capacity factors that are extremely well delineated, the more we're all going to have to work together on the analysis to make sure that the system stays reliable, and that it's a manageable cost.

ASSOCIATE MEMBER GEESMAN: The other thing I congratulate you on, I think you have to appreciate it's difficult for me to say positive things about PG&E in a public forum, but --

(Laughter.)

ASSOCIATE MEMBER GEESMAN: -- I would, in particular, commend you for taking a joint approach to this northwest challenge. Not only with other utilities outside the state, but with the Transmission Agency of Northern California here inside the state.

The Energy Commission, for a long time, has tried to draw special attention to joint projects. It's been our belief historically that those are better projects and stronger projects. I certainly think that PG&E is to be commended for linking up with an agency with whom it hasn't always seen eye to eye, to pursue these opportunities.

MS. HAPNER: Thank you. I think a lot of the credit, though, also goes to the other agencies. If we dwelled on the strengths and weaknesses of our historic relationships, and several of us around the table spend much of our time cleaning up those strengths and weaknesses and working on things that aren't nearly as satisfying as moving forward, we wouldn't ever make progress.

I think the win/wins of tomorrow will hopefully be like the win/wins of many many years ago. And perhaps we can bridge along the way some of the learnings on how to move through the periods where things have changed. I think that's what we're all hopeful about.

ASSOCIATE MEMBER GEESMAN: That's certainly the case.

PRESIDING MEMBER PFANNENSTIEL: Further questions here? Move on to Randy.

MR. HOWARD: Good afternoon, Commissioners. Thank you for the opportunity. Also in the interest of time I had provided a handout in response to the questions. So I'll just make some general comments.

And one is I fully support what Dede spoke about on a number of items including, you know, clean up of the queuing. I think there's been an abuse there, and even L.A. has seen it. That really needs to be cleaned up.

One of probably my -- we have a unique opportunity in L.A. because we do both, as a vertically integrated, I have the generation planning under me, and I have the transmission planning under me. And I bring those two together. And I can do that, not being a FERC-jurisdictional entity. So I have a little bit more benefit to get some of the transmission built.

And most of our transmission projects, we have three very significant projects, are related to renewable projects that we are building, or proposing to build. And in the case of L.A., where my mandate is to own and operate approximately 50 percent of our projects, the transmission is critical to delivering on those.

And we do look at diversification of those resources, particularly when we're focused up in Wyoming, looking into Oregon, in the Tehachapi area, and also into the Salton Sea/ Imperial County area for some of those wind resources.

A couple barriers, though, that I'd like to highlight. And one has been a challenge for us. And that's related to those entities under the Cal-ISO versus those of us that are not, and our ability to work together.

And we have had just a number of challenges going back to a model where I think we have a long history of joint projects. And it is our desire to have more joint projects. But as we're seeing in our southern transmission system upgrade, and that's the upgrade to Utah, where we hope to bring down some additional wind resources out of Wyoming, as well as Utah.

Several of the smaller municipal utilities that are now under the Cal-ISO have issues related to cost recovery and participation in that. And so it allows for some uncertainty and some ability to jointly plan and do some of those projects.

So there's a barrier that we're working our way through, and I think we're coming around in some additional collaboration with the Cal-ISO and some of our IOU friends to get some of these other projects built.

On the greenpath north, you know, we find ourselves in a situation where there's controversy over is one project going to take care of the need for the other. And we are in a planning mode where both the utilities have separate needs, separate requirements. Yet we're so focused on getting the renewable that we don't have a lot of time to also work through all of the issues related to the reliability benefits that take place in a larger upgrade that's happening.

So, I think some of the focus on that renewable is taking away from some of our other planning requirements that we would normally do. It's just that time constraints aren't allowing everything.

And then probably lastly for us, and the complaint I'm getting most often from my planning team is it's such a dynamic process right now, where it's hard to take a snapshot at any one point and say this is how we're modeling the impacts related to building the system out, or the interconnection related to the system.

It's because there is so much activity, so many proposed projects, so many things in the queue that are unknown whether they're going to happen or not. As you try to model them it becomes very very challenging to come up with a result that's believable, or one that you're going to trust and bring forward.

Not necessarily something we can take care of here today, but I think we're all struggling with how dynamic the changes are and the proposals that are before us today.

So I think in collaboration LADWP has indicated that we are going to actively participate in the subregional planning activity. We think there's good benefit there, and we hope to jointly bring forward some additional projects.

ASSOCIATE MEMBER GEESMAN: I would strongly encourage that participation in subregional planning effort. As you saw last weekend, I guess, The Los Angeles Times is on your case with respect to some of the potential routing of the greenpath.

We've been supportive of the greenpath project, and generally because you seem to be able to get things done. We try to stay out of your way on things. But I think to the extent that you end up being boxed in or characterized as a stand-alone entity, there are those that think you don't have interests broader than your own city limits.

And I think it would be in everybody's interest, as I know your board is intent on doing, you demonstrate a larger set of interests than simply within the city limits of Los Angeles.

We have no desire to exert jurisdictional authority that we don't currently have over your planning or permitting. And I think that it's important that you be engaged in the regional efforts that I know your board and city council and mayor are all committed to doing.

MR. HOWARD: And we are committed to doing that.

PRESIDING MEMBER PFANNENSTIEL: Further questions here? Juan.

MR. SANDOVAL: My name is Juan Sandoval from IID. Also, for the sake of time constraints, I'll go quick through this, and I'll provide handouts for the answer to my questions.

Let me just point out, as you probably are aware, Imperial Valley has a widely dispersed renewable potential. We try to draw, you know, bring a map for presentation, but it was not possible, but IID has potential everywhere in our 6500 square miles, you know.

Also we have currently we are wheeling 500 megawatts of geothermal to the ISO. And we have about 860 megawatts of generation, new generation resources in our queue with 18 projects. All sizes, you know, but most of them, you know, not larger than 75 megawatt units.

The benefit that we have is that we have significant amount of transmission already available in the Valley. About 500 miles of high voltage transmission line; 300 miles of those can be upgraded to the 30 kV. Those were identified in the Imperial Valley study work group.

But also I would like to point that we have 680 miles of 92 kV transmission line, a very convenient voltage. You know, that is located almost everywhere. And it provides a very low-cost option for the small generators to interconnect to the grid.

Also 200 miles of 34.5, you know, we have seen units as small as 5, 10 meg units that easily we can interconnect, you know, with minimal changes to the grid.

But one of the things that I would like to point is we have most of this energy, you know, with identifying a delivery point to the ISO. And we currently have Path 42, which is our tie with Edison. And I think it will be convenient, you know, to -- well, we also expect to continue working with Edison, you know, obviously a stakeholder of ISO, in assessing the needs to deliver this energy, or the -- needed in the ISO side or Edison side of the fence.

And I think we are facing these issues about queue, you know, and all the impacts, et cetera. And to me, you know, this is a low-hanging fruit. We have very low-cost options.

As well, we are also working with LADWP and greenpath north. We have our Indian Hills-Devers project which is going to be a part of the greenpath north. And we are cooperating with San Diego, also, in building the 500 kV line.

But this low-cost upgrades, you know, require attention. And we are more than willing to participate, you know, with the state -- the ISO.

In regard to the second question we believe that most of the questions have been answered, you know. We have been actively participating with IBSG. Let me just give you a brief update.

Most of the high voltage transmission upgrades identified in the IBSG are network operates. It means that the generators will receive the benefit of transmission credits. As a good example also that we have identified some of those upgrades as needed for reliability, IID's reliability, we are proceeding with. The -- for Highland El Centro is the 230 kV double circuit line. And we are moving in those type; upgrade is going to be done as part of our transmission expansion plan.

And also IID is conducting our programmatic EIR. You know, this is our own; it's not the one that was identified in the IBSG. But we're moving forward, you know. We have been getting the consultants, -- all the routes, et cetera, and preparing all the documentation to get all those upgrades, you know, permitted, to move forward with the plan.

And that's all, that's what I have.

ASSOCIATE MEMBER GEESMAN: We endorsed the Imperial Valley improvements in our 2005 strategic transmission investment plan, and continue to see the work that you're doing as being of statewide significance.

And if there's anything going forward that you can see us being able to do that's of assistance to your efforts, please bring those to our attention.

MR. SANDOVAL: Okay, will do.

PRESIDING MEMBER PFANNENSTIEL: Jim.

MR. SHETLER: Good afternoon, Commissioners and staff; I'm pleased to be here today to represent the Sacramento Municipal Utility District.

I don't think there's a question that SMUD has been aggressive in going after renewables. We're doing so both through contracts and through building our own.

And as a result, over the last three years, we've been able to about triple our renewable percentages. We were successful in meeting our board's goals in 2006. We exceeded those in our requirements, and we're now moving forward to almost doubling that by 2011 to come around 23 percent for our total, our two main renewable programs.

In addition we've been, I think, fairly lucky in being able to divvy that renewable resource up about equally between wind, small hydro, geothermal and biomass with a small amount of solar so far.

And that also has allowed us to have about a 50/50 split between baseload renewables and intermittent renewables, which we like, as well.

But we look at going forward to 2011; clearly transmission is one of the issues that's facing us. And I'd like to just take a few minutes to address the questions that were asked.

On the first one relative to barriers, we think there are probably four that we would offer up, some of which have already been discussed.

One is the regulatory process. We think it would certainly help if there's a way to simplify it. I hate to use the word one-stop-shopping, but if we can maybe limit it to a couple of stops that would help an awful lot. And get some integration between what goes on at the state and federal level.

Secondly, obviously transmission, dealing with the fact that the distances involved between many of the resources and the load is a major issue. One thing that we are looking at, and we think ought to be at least pursued a little more aggressively, is to the extent there are resources that are closer to the load, we think they need to be looked at seriously and developed.

We're focused very much on biomass here in the Sacramento region and trying to make sure we're developing that.

Third is I don't think we can forget about the grid needs. Obviously the transmission that's out there today is very critical to assure reliability of the grid. So as we go forward and look at how transmission fits in to deliver renewables, we have to assure that were also looking at how it fits in to assure that the load is being served reliably.

And then looking at planning horizons, I think we need to get in as early as possible. SMUD has a long history of working with our neighbors, PG&E, through TANC, the other municipals in the area, and Western, in trying to do transmission planning as early as possible. We think that's a key. We think we -- expand that, as Dede mentioned. And I think we're all interested in expanding beyond California borders. I think we need to make sure we're integrating those entities into the planning process as early as possible.

On the second question about looking at renewable resource areas and interconnections and corridors, I think the short answer is yes to all. We should be doing that. But in doing that I think we need to make sure we do it in a way that properly integrates, as I mentioned earlier, with other entities.

We also need to make sure that all the stakeholders are at the table as early as possible.

And again, making sure that whatever we do is done in a way that reflects both reliability and access to resources.

And then since a couple of comments were mentioned here, I'll kind of go off on a short tangent. One of my other roles, as far as also being at SMUD, is I'm a TANC Commissioner. And though I'm not here representing TANC, I think I can at least talk for 30 percent of TANC when I say that we are very much looking forward to working positively with PG&E. That may not always have been the history between SMUD and PG&E, but I think there are operational reasons to do so. Makes sense for California, and we're looking forward to doing that.

In saying that, one of the other hurdles or barriers that at least from SMUD's perspective, and I think Randy mentioned this a little bit, for those of us that are not within the ISO, and we start talking about joint projects that are shared between nonISO participants and ISO participants, there are some challenges on how that transmission is operated and how the benefits of that transmission flows.

Certainly there's a long history between at least northern California munis, and I know PG&E, and on working that out. We think that can be done. But it is a challenge, and we are approaching that in a positive vein.

And with that I'd be happy to answer any questions. And I will provide some written comments at a later date.

ASSOCIATE MEMBER GEESMAN: What's the status of your pumped hydro project?

MR. SHETLER: Oh, you need to come join me in Eldorado County on the 26th, come on up. We are, at this stage, awaiting the draft EIR from FERC. They have the settlement agreement in front of them.

We are hopeful that we'll have the draft EIR around the June timeframe. That will be the basis for our CEQA document. That'll have to go through our process, and, of course, the Water Board has to review the 401 permit.

My guess at this stage is sometime in 2008, if I'm real lucky, we'll have a new license which will include the Iowa Hill (phonetic) pump storage project.

In parallel, we're working very aggressively with the local community up there to identify concerns, mitigations. And work those into our planning process.

Having said that, we do view this as a little bit of a long process. We're probably not going to be going to our board for a final decision till sometime in the 2010, 2012 process. We need to do another round of more detailed design and evaluation of costs from there.

ASSOCIATE MEMBER GEESMAN: Thank you.

PRESIDING MEMBER PFANNENSTIEL: Tony.

MR. BRAUN: Commissioners, thank you very much; I'm Tony Braun on behalf of the CMUA, which is the statewide association of municipal utilities. And maybe I can just take two minutes to sort of wrap things up here in a bow.

Both Mr. Shetler and Mr. Howard talked about working with the other TOs and with the system operator in trying to maximize the opportunities. And I'd like to expound upon that a bit.

If you look across the west a very large percentage, substantial percentage of major transmission and generation plans are jointly owned among numerous utilities. And it seems that for whatever purpose, the sizing, finance, what-have-you, those types of major investments have always lent themselves to that type of approach.

I would say that -- I would count myself among the people that when we passed a law ten years ago, we were going to move away from that paradigm, that there was going to be one way of doing things, and everyone was going to be under a particular umbrella.

Well, that just didn't happen. And what we have now is two regimes. And what I would put out there as a plea is that we're in this place where we are, and it looks like that is pretty much a stable state. And that we need to really get past the philosophical issues and on to how do we get these projects done; and how the people who are going to be putting up the dollars can be assured that they're going to get beneficial use for the benefit of the ratepayers.

When an Anaheim or Riverside that are participating transmission owners look at a transmission project right now, because they're within the ISO system, in the future they will get, if they build transmission they will not get a physical delivery right to use that transmission. They will get a right to a slice of the pot of dollars.

That right to that slice exists whether or not they build that transmission or not. So there's really no linkage between whether they build it or not. They can get those rights and be guaranteed of holding them if their ratepayers pay for the entire cost of the facility, rather than get it rolled in.

But even holding that financial right is a risky thing, because it can be an obligation to pay into the pot of congestion dollars rather than getting payment out of it.

So we need to give some hard -- we've adopted models that are in other markets, and that was -- there were a lot of good reasons to do that. But we need to think, going forward, if we want these entities to be potential transmission owners and help build new projects, how can we insure that they get beneficial use, whether it's a financial or a physical right. And we need, I think, to be a little more creative and open-minded about how we construct that.

The other thing I would note is a lot of the questions and a lot of this discussion that we're focused on barriers to renewable transmission. And it seems like except for a few discrete issues we're really talking about barriers to transmission infrastructure development.

And I think it's helpful to put that in context, because anytime you're looking at a billion dollars' worth of an asset, you're looking at a whole host of factors, not just meeting one goal. And we can all hypothesize scenarios where, in fact, focusing on one goal could work to the detriment of meeting another goal.

So, as always, we would urge an integrated analysis. And I think that's the intent. It's just that sometimes because we have that immediate goal right in front of us, we're looking at it all in the context of meeting that particular goal. And we might get offtrack in that regard.

The last thing I would note very quickly is what we would like to see, we don't have some of the joys of working through the CPCN process in San Francisco and the like. So your interaction with that process, we are blissfully mostly ignorant about.

But what we would like to see you do is a couple of things. First of all, I think that you have a tremendously valuable role to be an independent source of thought and analysis. And I see some of the proposals and projects for analysis, whether it be the issue of integrating the intermittent resources, to me that is -- we talked a lot about it, but still, given the enormity of that issue and the size, going forward, and potential immediacy, it seems like, from our perspective, it's not getting enough attention. So you can be a valuable source.

And then when I hear Dede talking about the northwest and our folks looking at opportunities for renewables outside, but when I go over into the building and I see legislation that potentially would curb that, I think that there is a valuable role for the Commission -- and

I know I'm asking a lot here -- to identify and expose those types of policy challenges, when we have maybe some contradictory goals.

We have local capacity obligations that Mr. DeShazo's seen too much of me in some of these discussions. At the same time we've got air boards that are putting serious barriers to building in those same local areas in which the grid operator needs the capacity to keep the lights on.

I've already talked about the legislative challenges. We have a lot of competing policy goals and we think this Commission is in a good place to identify those, expose them, shine some light, and maybe identify some solutions to them.

PRESIDING MEMBER PFANNENSTIEL: Thank you to the whole panel. Are there questions from this audience or on the phone or on the Webex?

MR. NAJARIAN: We're going to go ahead. There's no questions -- we'd like to unmute the phones for the phone-only Webex participants at this point.

Are there any comments from the phone-only participants?

(Pause.)

MR. NAJARIAN: Okay, I think we can proceed. Thank you to the utility panelists. We appreciate it, great effort.

We'd like to now call on the developer group. And as they're being seated I'll go ahead and introduce them.

Greg Blue is here from enXco Development Corporation. He's their Policy Director.

Rainer Aringhoff is General Manager or Solar Millennium.

Steven Kelly, Director of Policy, Independent Energy Producers.

Hal Romanowitz, President and Chief Operations Officer, Oak Creek Energy Systems.

Vince Signorotti had to leave the workshop earlier this afternoon; he won't be here today. He does have a significant amount of comments to provide. He'll provide those in writing.

So, we'll go ahead and kick this off now and start with Greg Blue, enXco.

MR. BLUE: Good afternoon, Commissioners. I applaud your perseverance for hanging in there. And I know that we're behind schedule, so I will be brief. And we'll be submitting some written comments with a little more behind this.

enXco is a California-based wind energy developer who was -- since the RPS solicitations began in 2003, enXco has permitted and developed 40 percent of all the online wind projects in California.

Currently in California we have 450 megawatts to be permitted this year, with another 3000 megawatts in the development pipeline towards California's RPS. And out of those 3000 megawatts, enXco is expanding it to solar. So some of those are solar projects.

However, again, as everyone here knows, a lot of these projects are going to be dependent on these transmission issues that we've been talking about today. So this is a very important topic for us.

Just getting right to the questions, and I'm just going to briefly -- a lot of the issues I was going to talk about have been talked about already today, but I think a couple of things are worth noting.

The 2006 IEPR update identified lack of

transmission infrastructure as the most critical barrier to meeting the mandated RPS. We believe that is the case today, and I'm assuming that that trend will be noted in this IEPR, as well.

I think one of the main barriers that hasn't been talked about today, I think it was alluded to by Rich Ferguson earlier, but one of the barriers is in our transmission planning process in today's electric system.

As Rich showed us with his graph, as a result of AB-32 and the 33 percent long-term goal, California's electric system is going to be drastically different in the future. And we think that that's going to cause fundamental -- going to cause a need for a fundamental change in the planning process, where nonfossil generation is going to have to be looked at as the preferred resource in California. What I call the new baseload. And then having dispatchable fossil generation available to fill in where needed.

enXco also strongly supports the continued use of cluster transmission studies. If we do go about changing the queue system, the interconnection queue system that's been discussed today, that would be very important. Because if you study these things in clusters, it will eliminate the need to restudy these interconnection requests when there are changes in the queue.

We also, of course, believe that, and it was also alluded to earlier today, that when you are doing the transmission planning that you should include reliability, economics and policy considerations. And we need to see some more of that in our planning.

I think one thing that hasn't been talked about today, while it's not on point for today's workshop, I hope and enXco hopes that we see some discussion about this in the IEPR. It is the issue of utilization, better utilization of our existing grid.

This could include things like, I know it's been talked about a little bit, but relieving some of the existing bottlenecks within California. Perhaps installing dynamic line rating systems which allows some additional capacity to be available at times. The dynamic line rating systems basically feeds real-time information to the system operator regarding weather conditions and the like, which would allow potential intermittent resources to deliver additional energy on the grid.

Another possibility is for California to reexamine the reliability standards and the planning criteria. How wind could utilize unused transmission capacity for 99 percent of the time, or a certain percentage of the time, and still fully protect grid reliability through special protection schemes to turn off wind in emergency conditions.

It's my understanding that these types of things are being discussed in some areas in California. We think if we could have perhaps some discussion of that in the IEPR, I think that would help start that debate.

Briefly, question number two. Identifying preferred renewable resource areas from an interconnection and environmental perspective. We think there may be some value to that. But, for example, and I'm just speaking from a wind perspective, we know where the preferred renewable areas are. We don't really need a process for that.

But I think it would be helpful and it would be beneficial for developers to know, like from an interconnection point of view, and an environmental permitting perspective the best locations for development.

We also think it would be beneficial to include in there issues regarding radar, aircraft radar and military issues, as we heard earlier. That's becoming one of the major issues that we're finding. It's surpassing avian issues for us, as barriers, from our point of view, of developing projects in California. So this interagency task force, I think, is going to be critical. Again, any encouragement from this Commission towards that would be very helpful.

Every developer tries to eliminate our fatal flaws in a project as soon as we can. And this type of a process would help in that evaluation.

2.b. was talking about identifying interconnection points on the grid in collaboration with transmission owners, load-serving entities, control-area operators and such. Basically that's describing the Tehachapi model. We strongly support the continued use of the Tehachapi model. We think it was very successful.

And we see that when you identify the

major substations upfront with the collaborative group, I think it's very helpful for developers to know where to interconnect their projects to.

Lastly, about the corridors. We support the designation of transmission corridors, which can be instrumental in getting these lines built. These corridors do send strong signals to the developers; and they do affect our land acquisition strategy. Because we're out there right now trying to acquire all the land we can, where we think we need to be putting projects up.

However, I think, as we talked about these corridors, there's been discussion today about the width of the corridors. And I think we all need to understand that when you're talking about the width of a corridor, you're talking about local setbacks required by county use permits -- which, in wind, is usually three times turbine heights -- and you start talking about these types of things, that if you run a corridor through some of these renewable resource areas, there's a potential to eliminate some projects. Just so that everybody's aware of that. You know, these corridors do need to be wide enough for future growth.

And lastly, of course, California transmission corridors need and must synch up with regional transmission corridors. We agree with PG&E and others that in order for us to reach our long-term goals we are going to have to go outside of California borders to bring in some of the renewables. So we think that's very important.

In conclusion, we're very supportive of this IEPR process. Again, we do believe that these issues that are being studied in this IEPR are going to be vital for us to reach our 20 percent RPS, and even longer term 33 percent RPS.

And my last note is that renewable developers are going to be unwilling to spend significant development dollars until we see a strong transmission plan. And addressing these issues is going to help us accomplish this.

Thank you.

MR. NAJARIAN: Any questions?

Rainer Aringhoff, Solar Millennium.

MR. ARINGHOFF: Thank you very much, Commissioners, having the opportunity to address some points on transmission constraints and general development issue with respect to one renewable technology, which is solar; but it's a specific one, it's concentrating solar-thermal power.

This technology has been built, first exploited very successfully in the Mojave Desert some 25 years ago. These plants are still operating very reliable and are contributing to the coverage of the peaks, the summer onpeaks in southern California specifically.

This technology was dormant in the last 15 years almost simply due to the fact that there was no incentive available in a form that was sufficient to cover higher initial operation and investment cost.

Simply spoken, the technology today will cost anywhere between 10 to 15 cents per kilowatt hour. But the value that technology is providing is specifically that most of that is summer onpeaking power.

So, there is a revival. You can observe that internationally. Our group in Spain is now constructing two bigger projects in capacity; compare each to about 90 megawatt, in Spain; total investment is on the order of $700 million. And there are another 20 projects underway. And you can see that developers are coming and looking at

California.

I think the specific hype that developed here in the last year was that the investment banks were looking at and saw that CSP, concentrating solar power, is of specific interest because of an available 30 percent investment tax credit that could be nicely organized as each of these installations cost anywhere between $100- to $500-million. It's one deal; it's more than you can cover, even with bigger wind parks.

So, that is the background. But what is the reality. The reality is there are other than photovoltaic that are more distributed technology on the solar side. You can use this technology basically only in high insulation areas with clear skies and therefore a high direct normal insulation level. That you will find typically in desert areas.

And you're looking at those, California has plenty of those. The Mojave Desert definitely is the best of all of these deserts. Just imagine the radiation level which you can transfer into generation costs directly linear, is about 10 percent better. So any installation in the Mojave Desert is 10 percent cheaper than if you build it in Imperial Valley or in Arizona or in Nevada. And this is why the Mojave Desert is of specific interest.

But if you are looking, there is another point. It is, at the same time, that location where the resource is next to the biggest load center, one of the biggest load centers in the world. So there are 50 to 80 miles distance just to the L.A. Basin. And this is a unique situation, and therefore the Mojave Desert is of specific interest for this technology.

Now, the obstacles are that you have a grid situation where apart from a very few lines, mostly, I think that's LADWP's lines, the rest is congested. Everything that has to flow down south from the Mojave Desert is congested and ends up at Lugo or at Vincent substations.

And this is why we suggest -- there are studies that have been developed in the past years that show that if California is going for the 33 percent for the AB-32 goals, of 33 percent renewables, you have to do something on planable, dispatchable peaking power. And one of the very few ones that is offering that is concentrating solar power.

So there would be a specific reason to enforce and to insure that this technology can develop there. Plans are underway; a lot of plans are underway there, but the situation is that you won't physically get the power out today.

Projections say that until 2020 up to 6 gigawatt can be built just in the Mojave Desert, which would be a significant contribution. And which also would help other technologies, like wind, to even expand because here comes a sort of a load backbone into the scenario that you have a peaking power or planable peaking power available.

It looks like today that nothing will flow down south except maybe a few hundred megawatts before 2012, 2015. Which would really be an obstacle for the implementation plan to reach 33 percent until 2020.

So, from that point of view, we strongly suggest that the Tehachapi study group is a fine example of being expanded. And what I understood is that there are plans underway, or it has already been implemented, that the Mojave study group will also work on these issues.

We strongly support that. And I think all of the companies I know that are working together in the concentrating solar power sector will contribute -- not only welcome, but actively contribute to this process. This is to your first question.

The second one, we take the wording development corridor almost literally. Yes, we think it is needed. Also, in view of the fact that we admit that the Mojave Desert is a sensitive habitat, therefore a regional planning, a long-term planning has to take place. It cannot be isolated here and there as spots of production centers. They are then desperately looking for the interconnection. But there should be clusters where larger clusters of projects can be built.

The suggestion, and I have given you a map describing the situation a bit. One of the concepts could be of using the highways, mainly highway 14, highway 395, and highway 58, which are crossing the Mojave, where adjacent to these highways where anyway there is a lot of development. There are even dump areas which could be used. If you just use the airplane dump areas in the Mojave Desert, where over-capacities of airplane are stored, you would have the first 2 terawatt hours of CSP production.

And therefore we strongly recommend in a joint effort together with BLM, together with the Energy Commission, together with the Department of Environment and the Department of Fishery and Game, to work on a plan to designate certain development areas where a combination of transmission path, plus land development, in a consistent way is prepared.

This is basically our proposal to you to consider. Thank you.

PRESIDING MEMBER PFANNENSTIEL: Thank you. Steve.

MR. KELLY: Thank you, Commissioners. This is Steven Kelly with the Independent Energy Producers Association. And, as you know, we represent the full range of renewable technologies installed and hoping to develop projects in California. Sometimes that's a blessing; sometimes that's a curse.

In this case I think it does afford me an opportunity to provide some comments today that are a little different than you might have heard. I haven't heard a lot today that I would disagree with. But I don't want to reiterate all those comments, either.

But I would like to step back and talk about what I think are some of the critical barriers. One being kind of a large theoretical barrier that I'd like to address. And then, two, get into some more specifics. And then finally respond to the questions regarding the resources.

And the first barrier that I'd just like to bring up, and it's kind of esoteric, but I actually think the biggest barrier to renewables right now might be a language barrier.

It doesn't surprise me that we were not able to really develop a lot of renewables when we were talking about the RPS. But there is tremendous activity and movement forward now that we have a greenhouse gas issue policy in the State of California.

And I would like to see us move away from talking about the RPS because I do think we're creating problems for development, from a public policy perspective, and getting the public's endorsement of developing the renewables. And move to more of the language of global climate change, emissions reductions. Because that is where the RPS really is the tool to achieve those goals.

And it also strikes me is that it's an area in which the public has largely come to accept; that there needs to be significant investment to protect against the potential downside or risks or liabilities, if you were, of climate change.

And it's that investment that we're really talking about today. How much investment should we be making for renewables, and where should we make it.

And when we talk about the RPS I think we lose that sight. We're really talking, when this state enacted its greenhouse gas legislation, it really spoke to transforming our economy; something that it's not done before. We are really talking about transforming a primarily carbon-based economy to a primarily noncarbon-based economy. That is a huge endeavor, and that is going to cost a lot of money, of investment dollars, across the table.

And when the public perceives it in that way, though, I think they are more susceptible to agreeing to paying the investment, or buying into the investment. And whether it's transmission or electric generation, both of which are vastly needed, as you've heard today, the real impediment to doing that is the public's perception that it isn't cost effective. And I think they're thinking of it in terms of renewables as a counter-choice to natural gas, when they should be thinking about it as renewables as the primary solution to the climate change problem.

And if we can get the public thinking in that mindset I think we will be able to overcome some of the barriers that I see to both transmission and generation. Renewables are the solution. The cost comparison for renewables in my mind shouldn't be the natural gas model that we're using in the RPS today. It's really IGCC or nuclear, which costs billions of dollars.

But if we talk about spending billions of dollars on renewables today, all of a sudden people seem to think that we're spending way too much money. But I think in hindsight it will probably turn out that it's way too little when we look at the real alternatives from a climate change perspective.

So, I think the focus that we do in California today on least-cost/best-fit for renewables is a little misplaced. I'm not suggesting that we should buy all the renewables necessarily that are too costly. But the incredible minute focus on least-cost/best-fit is impeding our ability to move forward quickly to develop the renewable technologies that will displace and solve the climate change issue from a global greenhouse gas perspective.

And every year that we delay developing new renewables is an avoided, a year that we do not avoid the greenhouse gas emissions. So I think there's a need to move very quickly in this regard.

And in terms of this investment I'm talking not only of the transmission and generation investment that the private sector and the public sector is willing to invest today, but I'm also talking about the state investing in the staffing needed to get this done.

And for a couple of examples, not only at the PUC have they had to ramp up over the last year because of the delays of moving forward, but I think I'm hearing from a number of companies that are speaking, about the need to expand the staffing at the ISO that does the interconnection studies in order to smooth out and speed up the process for doing that work at the ISO on the queuing issue.

That is the type of human resource investment that is not being made or should be made now, as if we are transforming the economy, as I indicated earlier, that I think we ought to be moving very quickly on.

This is essentially a social good, this investment, in my perspective. And we should recognize it as such. And it may be that some of these benefits or the costs associated with this investment are going to be spread more broadly than they would have otherwise been. I think this is kind of the third category transmission approach to things, recognizing that there's a broader social good here.

And the quicker that we recognize that, and the quicker that we recognize the need that there is this public good, and that we don't necessarily have to get the cost down to the -- so that everybody's bearing their full share. Because the process of doing that is impeding our progress getting to the investment where we want, then the quicker, I think, we'll get there.

And that brings me to a more specific

issue about the need from an investment perspective about investment in regulatory certainty. And I think a lot of people have mentioned this today.

But we really need a process that the investor is looking at and can see and understand, so that they can start the process of bringing the millions, hundreds of millions of dollars to the table and plan to invest in California or in the west.

This primarily raises an issue, I think, of the need to perhaps revisit the issue of queuing. I think Dede Hapner from PG&E raised this issue as a problem. IEP, about a year ago, raised the issue of project viability in the ISO queue. I'm not here to recommend a solution, though I do think a public process highlighting, focusing on how to improve the queuing process is important.

From an investment perspective, if you were trying to pull in tens of millions of dollars, hundreds of millions of dollars, and the amount of money that you're going to need for transmission is moving around as people fall in and out of the queue above you, that makes it very complicated. We've got to figure out a way how to smooth that out and bring some more certainty to the investment community in that regard. So, I do endorse this Commission maybe taking the lead on looking at that.

In answer to the staff's questions regarding the preferred resource areas, preferred interconnections, I think it was mentioned earlier that most of the places, at least within California, where good renewable resources are located have already been identified.

I think the Energy Commission did a very extensive study on this awhile back. So I'm not certain that a lot of that work needs to be redone.

I do have a concern that if we started down the process of trying to identify the preferred resources we might get in a quagmire. My guess is that the concept of a preferred resource is going to vary by stakeholder, and you may get mired down in trying to identify what are the, quote, preferred resources, or not. So I wouldn't want to see that process impede our ability in the near term to move forward.

If there are preferred resources or

preferred location areas that the state doesn't already know about, we should be identifying those. I think that kind of study work is valuable. But we ought to be doing it in parallel and not in front of our ability to move forward with new investment in California.

So those are my comments. Thank you.

ASSOCIATE MEMBER GEESMAN: Steven, with respect to the queue issues, isn't that -- I mean I acknowledge our role as a prod of sorts, but isn't that more naturally public process performed at the ISO?

MR. KELLY: I don't know that it has to be at the ISO. I think I look to you as the prod in this regard. We're internally looking at kind of revisiting the idea of milestones. As you might know, back in the old QF days and standard offer days there were milestones in those contracts so that there wasn't a problem of impeding progress toward development.

I'm not here to suggest that I have the answers, because this is a very complicated issue. I think it's an issue that probably actually may sit well better here than at the ISO because of the -- there's FERC issues associated with this;

there are state policy issues associated with this. There are investment issues.

There are a lot of reasons why people are delayed in the queue. Some of them are valid, some of them are because they're not ready. And we need a place, I think, where we can identify those issues and assess them. And because I work in Sacramento, this would be a perfect spot to do it.

ASSOCIATE MEMBER GEESMAN: Are you familiar with the discussion of this subject, in general, in the ISO's 2007 transmission plan?

MR. KELLY: No. I'll be honest, I haven't been that engaged with the ISO's transmission project. Usually it gets to a level of detail with transmission planning and so forth, that I've often not able to keep up with it.

ASSOCIATE MEMBER GEESMAN: It's a pretty good narrative, and I think that if you do have the chance to take a look at it over the next month or so, I'd like to talk to you about it further.

I guess the other area that I'd like to at least register some concern about your comments, relate to the cost of renewables.

Because, you know, there's still enough of a ratepayer advocate in me to think that we're looking for opportunities to drive costs down, not drive costs up.

And to me the significant thing about the RPS program, as you know, this Commission has been, at times, painfully candid about our assessment of the RPS program. But I think one of the significant things about the contracts that have been signed, 80 contracts, 75 out of the 80 contracts came in below the market price referent.

That's not a comparison against nuclear power; it's not a comparison against IGCC. It's a comparison against a new, ultra-efficient, combined cycle natural gas plant. It's not even a comparison against the status quo inefficient jalopies that our system continues to rely upon. Seventy-five out of those 80 contracts, cheaper than investing in a new natural gas fired power plant.

That says to me that we're doing the ratepayers a grievous harm by not investing in more of these renewable contracts. And that the slowness with which the RPS program has been able to convert contracts into steel in the ground, megawords into megawatts, is really an assault on the ratepayers' interests.

I don't think that our rate regulator has been as diligent in pressing this issue as, I think, the Energy Commission would like to see.

So your comments about cost I hear in other places around the country. And I'm not prepared to say that they're not an accurate representation of the situation in some of the other states. But, in a system that is so heavily dependent on natural gas fired power plants, renewables have actually turned out, if you believe the contract terms, have actually turned out to be cheaper than our natural gas alternative.

MR. KELLY: If I may respond. I'm not talking about eliminating the competitive process for deriving the number of megawatts that the state wants, the 33 percent or anything. What I'm talking about is using that process. And I think that will derive the lowest cost that you can possibly get for projects that can be developed.

The contracts that have been entered into today, you still have to wait to see whether they actually get developed. And I also think that a lot of those are part of the low-hanging fruit; that we might have moved past that first year; we're now looking at perhaps more expensive stuff.

But my comments were more on the line of the combination of the transmission that's obviously needed to bring on the renewables to meet the 33 percent goal, plus the new generation that is going to be needed installed to meet that goal is a tremendous investment. This sector, of all the sectors that are going to transform itself, in order to meet the greenhouse gas goals, is the most scrutinized as far as I can tell of any.

When the transportation sector does this, nobody's going to be asking some of these questions. And when the refinery or cement guys have to do something, I can guarantee, you know, it'll happen. There will be investment made. It'll be passed through to the consumers, that's what things usually are. And off we go.

But we have a process here in California that before we engage in that place where we pass the cost back to the consumers, you have this arduous process of nailing down to the tiniest detail the integration costs of all the wind and what it's going to cost to do that. Which I think is ultimately an unknowable answer, because load shifts, and wind shifts and so forth. And you never have a fine-tuned answer on that.

And some of it's just going to be investment will to get things done. And we may be over-invested at the end of the day in renewables; we may be under-invested. We won't know until about 20 years down the road, I think.

But what I do see today is that we're not getting enough steel in the ground in a timely manner right now.

ASSOCIATE MEMBER GEESMAN: Yeah, I don't want to get too far ahead of us in terms of our hearing schedule, but we do intend to address a little bit later in the 2007 IEPR process portfolio issues.

And one of the things that we raised in the 2006 report was whether this stand-alone engineering plant-by-plant comparison is embedded in the RPS system and the market price referent doesn't systematically prescribe an under-investment in renewables in terms of their portfolio value in mitigating gas price volatility.

The other thing that I take some exception to is the low-hanging fruit argument. To the extent that wind or solar technologies prove to be significant contributors to the renewable portfolio, both are technologies that are subject to volumetric cost reduction through the manufacturing process.

So the logic of there being such a concept as low-hanging fruit probably runs contrary to the price curve for those two particular technologies.

I acknowledge that steel prices, concrete prices, along with fossil fuel prices, have gone up here in the last couple of years. But it's not clear to me with respect to any of the technologies subject to that volumetric price reduction where the concept of low-hanging fruit comes in.

MR. KELLY: Well, if you look at the number of contracts that have been entered into under the RPS, a lot of them were existing facilities that re-upped, that restarted, already there; not new, per se.

My understanding about the cost of

materials for a number of the technologies, wind and solar -- and I'd defer to Solar Millennium here on the solar -- but worldwide demand for some of these technologies has got the production at its maximum output.

So, in some cases you're not seeing that cost curve happening; at least right now anyway. So, -- but, you know, the answer to your question, I think, is that if you have an open competitive process for this, the price to bring these things on is what it is.

ASSOCIATE MEMBER GEESMAN: That was the last point I wanted to call into at least some question. And, again, without getting too far ahead of us in our hearing schedule, one of the things that we do intend to devote some attention to in this cycle is whether the RPS tender process is really designed well to produce the most renewables at the lowest cost. Or whether the state might not be a lot better off trying to emulate the feed-in tariff structure that has worked so well in Europe.

The European Commission has been pretty clear in going through the experiences of the EU member states and finding a very high correlation, both in terms of volume of renewables, and low costs associated with feed-in tariffs, in comparison to the RPS tender systems.

Now, they're clearly not a direct parallel to our market conditions here in California. And I'm not suggesting that it would be easy or appropriate to simply directly transfer that mechanism into this environment.

But I think that particularly as we look at a 2020 goal of 33 percent, we need to expand our horizons as to what mechanisms are likely to produce the best business environment for the renewables industry, and the lowest cost for the utility customer.

MR. KELLY: I agree with that. In fact, I think I'm going to participate in that workshop and I'm reading everything I can on this.

MR. BLUE: Can I respond on that one topic? I just wanted to respond on the RPS issue. I think from our point of view the RPS RFOs, while we haven't seen steel in the ground yet, we're about to see a lot of steel in the ground.

These projects take several years to develop, as you're dealing with large amounts of land, a lot of landowners; you're dealing with one or two years of preconstruction avian monitoring and the likes.

But, for example, and Hal can speak to this probably as well, our company is gearing up like never before. Everybody has got more things than they can do. Utilities are working as hard as they can. There's RFOs every year. There are bilateral discussions going on every day. And as a direct result of RPS.

So, we think that it's been a huge driver in where we are and where we're going to be. Thank you.

ASSOCIATE MEMBER GEESMAN: And since 2002 California's been successful in bringing 248 megawatts --

MR. BLUE: That's right.

ASSOCIATE MEMBER GEESMAN: -- online. The State of Texas has brought 1700 megawatts online.

MR. BLUE: Right. Can you help us out?

ASSOCIATE MEMBER GEESMAN: What's wrong with this picture?

UNIDENTIFIED SPEAKER: Transmission.

MR. BLUE: That's another topic.

PRESIDING MEMBER PFANNENSTIEL: I think

we need to move on. Steven, let me just thank you for your comments and offer one observation, when you hit one of my -- when you referred to renewables as the primary solution to climate change. I firmly believe that energy efficiency is the primary solution, and renewables perhaps the secondary solution. Certainly in the cost effectiveness basis.

MR. KELLY: Yeah, I guess I was referring back to the Climate Action Team report that said something like if you got 33 percent renewables that was a huge chunk of the greenhouse gas thing.

PRESIDING MEMBER PFANNENSTIEL: Absolutely.

MR. KELLY: I can't recall where the energy efficiency came in on that. But I know that the RPS was the major driver in getting there as far as I can recall.

PRESIDING MEMBER PFANNENSTIEL: Thank you. Moving on. Hal.

MR. ROMANOWITZ: Thanks. I'm Hal Romanowitz, President of Oak Creek Energy. And Oak Creek is a long-time Tehachapi wind developer that is going through a very major expansion process; has gone through a very major expansion process in order to strengthen and expand our ability to deliver into the California RPS program.

We have announced projects between 1500 and 1600 megawatts now. The main one being the 1500 megawatt SCEEPA, and also the largest behind-the-meter project, we think, in the United States for wind energy.

Our pipeline is, you know, that we're looking at for the California RPS in our little region is probably in the order of 6000 megawatts. And our objective is to be a very cost effective supplier, you know, into the market. So we're organizing ourselves to do that by focusing.

It's been a long, you know, and painful process. I think we've been here many times in the past talking about issues and so on. And finally we're seeing some of this come together.

We're extremely appreciative of the processes, the way that they're moving forward, you know, the local planning. We think that Kern County's done a great job moving their process forward. We think BLM is making significant progress. We think transmission planning is making progress. And obviously with the large PPA announcement, we think that that process is working. So, you know, it's broken loose; you don't see the steel in the ground yet; the momentum is building.

We've geared up to have something north of $10 billion worth of, you know, money available to build what we've got to build. And so it's, you know, this is not a small undertaking. It's got lots of intricate pieces and so on.

That said, I think that there are some very significant lessons that are already, you know, clear; and that we need to take those lessons and amplify them and refine them. And that we'll really correct a lot of things.

For example, I think Cal-ISO was brilliant in clustering Tehachapi. I think it's underestimated what the benefit of that is. And I think that the process has not yet been completed. But this is, in my estimation, clearly the answer to the clearing out the queue, managing the queue, handling the queue.

Basically you don't have to change the whole process. You can make the existing process work simply by clustering. And then making the clustering work effectively.

So I think that's one, you know, very significant thing. Once you do that, then, you know, you make the cluster process go on an accelerated basis. And you look at the details of what Cal-ISO said about the cluster. Basically somebody falls out, the next guy comes in. So you can have a movement of queue positions through the clusters, but you can do the orderly planning of the transmission facilities; you can model and build them; all of this without having, you know, waiting for information.

And, you know, basically the FERC-mandated queue processing process, for all practical purposes in my estimation, is largely dysfunctional, but, okay, that's, you know, so you understand it, at least. And you can live within it and work within it. And as long as you're willing to not expect perfection, but understand what the process is and work with it, it works.

And, you know, basically the process in one case either the queue positions are -- the process is not meeting the FERC-mandated timelines; not missing them by two, three, four times. Or in other cases where they're meeting the FERC timelines. The studies that are coming back are ridiculous. They're not what we would consider competent studies because they're missing big elements, that make them useless.

So, you solve all of that by going to the clusters and making the clusters work. And then bring people in the clusters.

And so I think Cal-ISO has really been brilliant. We would encourage them to take this to the next step and carry it, you know, carry it through.

ASSOCIATE MEMBER GEESMAN: Hal, can I ask you, how do you envision the RPS solicitation process working in the future within a particular cluster?

MR. ROMANOWITZ: I think the two are separate processes.

ASSOCIATE MEMBER GEESMAN: They certainly are.

MR. ROMANOWITZ: Yeah, I don't see the two as together necessarily. I think, you know, you get your transmission, you get your RPS agreement. And as stuff becomes clear on what we've done, you know, you'll see that the utilities are capable of making this thing work.

We think we have something -- well, we didn't go in this process to get a PPA that we could announce. We went into this process to get, you know, a PPA that we could build.

And so we were pretty insistent on getting the details worked out. So this is something that's going to be built. It's going to be built as quickly as we can. And we're on the backs of the transmission people now to get things as quickly as we can, so we can get things done.

We're ahead, clearly ahead, we've been ahead for a long time, of the pipeline. We want to get things built; we want transmission so we can build it.

And this behind-the-meter project is an example. I mean everybody's going bananas now because we're sneaking in a project behind the meter, so to speak, some people say. Yeah, we can build it because there's not a need for transmission.

And we're ready to build. And I think that things will get built, handled that way.

ASSOCIATE MEMBER GEESMAN: So the utility has agreed to build transmission out to a cluster. Let me hypothesize there are ten developers in that cluster.

MR. ROMANOWITZ: Right.

ASSOCIATE MEMBER GEESMAN: How does the utility determine what price to pay to each of those ten?

MR. ROMANOWITZ: Well, it's not --

ASSOCIATE MEMBER GEESMAN: Through some kind of bidding process?

MR. ROMANOWITZ: You're talking about what price do they pay for energy they're building. Basically they're paying, you know, the RPS price is separate, it's bid. It's below the MPR. It's bid. And, you know, you, as a developer, on establishing your price, have a whole number of factors that determines what your costs are.

ASSOCIATE MEMBER GEESMAN: Sure, I understand that.

MR. ROMANOWITZ: And what we've done is -- I mean we've worked very hard. If we went just by conventional way projects were built two or three years ago, we would have horrendously high prices.

What we've done is said, okay, we're in this for the long run, and for making a major impact very cost effectively. So there's a series of things that we have to do, and we have to make happen, in order for that to happen.

But we got to have a PPA; we've got to have, you know, transmission. And we'll make the other things happen. We believe we have the expertise to make that happen. And we see the logistics of how to do it. And we don't really -- we see the turbine supply problem as a nuisance, more or less. It's something that we have to work around and we have to be smarter than, you know, the suppliers who are playing the games.

And we recognize that there are hundreds of megawatts of wind turbines sitting on the ground right now, as we speak, that have been delivered, because people paid deposits and they're taking delivery. Their projects weren't ready, so they're sitting. And they think they can get a premium for those turbines by selling them off to other people. And they're going to learn that they can't.

ASSOCIATE MEMBER GEESMAN: Once the utility has chosen to build the transmission out to the cluster, by what rationale does it pay a different price to each of the ten developers?

Are they not to pay the same price?

MR. ROMANOWITZ: Well, you're talking about an RPS bid versus a feed-in tariff, so to speak. And, you know, I would say that I personally was a very strong advocate for many years of the feed-in tariff, that concept. The, you know, ISO 4 sort of arrangement. I think it has lots of advantages. It works well.

I think that the RPS structure that we have now also works well. I think it's tough. You know, we had 15 months of negotiations to get a workable deal. But we got one.

And we had a counter-party who was very professional. And, you know, they were insistent on having their interests protected; we were insistent on ours. We have a lot of respect for them. We think they did well; we think, you know, we did a professional job.

And we think that the result is good; and we think the result will be good for California. So, going forward. So, --

ASSOCIATE MEMBER GEESMAN: Yeah, I don't disagree with any of that.

MR. ROMANOWITZ: Yeah, I think that, you know, basically in the end what happens is, you know, there probably is not, if you're competent in negotiating PPAs, you're probably not going to have a major difference between an RPS negotiation and a feed-in tariff in the end unless somebody's made a mistake. Basic costs are costs.

So, if you're going to have a result, you're going to have prices or costs that are in a reasonable range. And I think that you will get a comparable result regardless. And I think the utilities are alert to the concept that different people can produce energy at different costs. And, you know, they're trying to squeeze out for the ratepayer everything that they can get. So, you know, they're tough negotiators.

ASSOCIATE MEMBER GEESMAN: Least-cost/ best-fit.

MR. ROMANOWITZ: Yeah.

ASSOCIATE MEMBER GEESMAN: I've heard it before.

MR. ROMANOWITZ: But, yeah, that said, you know, one of the really critical things is how you get this transmission into effect. And, for example, you know, with Tehachapi, it was a painful process. Almost ten years. We started, myself and somebody else, in 1998 said, you know, the fighting between the industry and SCE is no good. It's time to change it.

And we started a dialogue; and we went through and built up, you know, a collaborative process that then the PUC adopted; and then Cal-ISO. And it really took all the way to Cal-ISO to get the thing right. But it was a good process; it was a constructive process. And I think by learning from it, you know, it can be shortened for everybody else.

But a key critical component of this is that you get certainty for transmission. We were able to get the transmission for Tehachapi being essentially 100 percent networked. The one little piece that isn't networked, I've laid out a proposal into another stakeholder process on how that piece can be made network and should be made network.

And all of our pipeline is virtually network transmission. So we've been able to locate good projects where the transmission is network, and we'll get into that in a minute, because we can show you some, you know, the places we're talking about really need massive transmission.

It's a scale that everybody is sort of laughing at, at this point. But it really shouldn't be laughed at. It needs, you know, it needs serious attention. And I think when you start looking at the clusters and handling them and managing them, you'll see that will work. And so on.

But one issue is out of Tehachapi you have over 50 percent of the cost is really for what I would call deep upgrades. When you get, if you got all of the costs of Tehachapi really laid out and correctly divided, 60 to 70 percent is probably deep upgrades. Stuff not needed just for Tehachapi, but it's stuff that benefits the whole system and takes the energy into the load center.

It's even going to affect -- everybody is saying now and recognizing in the studies, well, Tehachapi is going to affect south of Lugo. Gee, that's not Tehachapi. You know, but Tehachapi is being charged for it in the $1.8 billion.

And all of these deep upgrades are clearly known, what they have to be. And they are the toughest things to do. Tehachapi will be done in 2010, or 2011 by the schedule; 2010 if they do what I think they will do, we'll have all the transmission we need in Tehachapi. But the deep upgrades are going to take a couple of years more.

And we should be starting now for all of this. Like Solar Millennium has pointed out clearly, you know, there's more needed for their efforts south of Lugo. If you look at the other places we talk about, it's clear that the deep upgrades dominate the issue and the timelines. And so far that isn't focused out.

And the whole planning process is constructed in such a way that the deep upgrades are over-planned on the back of each project.

For example, for Tehachapi, in effect, the L.A. load center was unloaded. And so Tehachapi had to pay to get everything in, you know, from Vincent into the load center. Rather than redispatching coming in. And, okay, that's all right; just recognize it shouldn't be on our back.

But get it into the system; get that planning going. And really separate it. Because, you know, regardless of whether it comes from Tehachapi or, you know, wherever, you still have to get into the load center.

And you really should build what's needed to go into the load center, and you should not over-build it. In other words, maybe you over-build it by 10, 20 or 30 percent. But you don't build it -- over-build it by two or three times, which is what you will find will happen if you continue the existing planning process to is ultimate end just for what's in the queue.

In order to get the transmission planned on a rational basis there's an absolute need for two firm commitments. In Tehachapi SCE has made that commitment, you know, in writing. But, as I read it, it's sort of probably a nonbinding commitment. But what all of us are planning is going to happen, and that is that they're going to upfront fund all of the network stuff and get paid back, you know. And that they're not going to cause us to upfront fund. If we have to upfront fund that creates, you know, a net set of issues.

And that commitment is needed to be made early in the planning process with all of these clusters. You start a cluster and SCE went to court and got -- the appeals court said that they had the right to make that decision, and that must be respected.

But then conversely, I think they should have an obligation to decide that they are going to upfront fund, or then they should, you know, whatever the utility is that is involved should decide to get out of the way and let somebody else come in and do it. So that you have, you know, rational early planning, and you can get the transmission built on a quick basis.

And, you know, I think we respect very much their right to build it, and their desire to build it, and we think that they're doing a good job. So, you know, we encourage it, but we think that that decision just -- that must be made early in the process.

Another issue that to some extent the clustering will resolve, but under the present queue process, the confusion and miscommunication related to wind turbine models is creating a disastrous process. There's no need for it.

In WECC there's a -- TSS is voting on Thursday on a proposal that says that they have no wind turbine models. I can tell you that we've given them over multiple thousand megawatts of wind turbine models, so that they have models to do their planning with. You know, so there is a miscommunication.

I think the integration issue is important to take care of. The work that's being done in IAP is exceptionally good. I think it is -- there's some confusion as to the result maybe, and that's being cleaned up. But once all of that's done, there's going to be a result there, but it's the implementation of the technical capability that is identified by like GE and the IAP, the process to utilize it has not been decided. So you've got to carry that an additional step.

And that's crucial, I think, to the process of getting effective transmission. And as others have said, recognizing that natural gas is going to phase down or phase out of our generation mix.

Okay, last question, and I'll go quickly so I don't use up too much time. Where is the, you know, where is the choice transmission, the siting. And essentially we see Tehachapi and east as the very ripe area. Essentially the existing substations, Tehachapi number one, Tehachapi number five. And then going east, Kramer, Pisca, Eldorado and Mojave, which are just over into the

Nevada border. All Cal-ISO substations. Those are the crucial corridors. They're vital.

It is crucial that SCE not diminish, but must expand Eldorado and Mojave and that whole path inward. That that already has over 9000 megawatts in the queue. We see that there will probably be over 12,000 megawatts in the queue from there; probably another 2000 coming in at Kramer.

And, you know, when you just look at that one path you have over 50 percent of what you need for your RPS. So, a good, cost effective generation. And so there's a lot there. And you could concentrate one place and you've got it.

And, you know, everybody's looking everywhere else and you're forgetting, you know, downtown. You have major transmission and you should use it.

And a problem is, like with this 1500-foot planning corridor, is not adequate because you must separate two major lines by at least 2000 feet in order to get full capacity out of the two lines under Cal-ISO's rules. So you've got some very major issues, and the paths in from Eldorado and from Mojave are going to have to have two, three, four lines, 500 kV lines. So you've got a fundamental issue in your corridor thing you really need to address.

Oak Creek has had, coming right through our project, we're going to have four 500 kV lines. We've now had a good coordination with SCE after we finally went to the PUC and testified that we weren't being dealt with. And we were going to have 400 megawatts worth of project wiped out by these lines. And we've been able to work with SCE effectively. And these lines come right through our project. And we will have quite negligible impact now that SCE has really worked cooperatively with us. And so this can be done.

But like a crucial thing is that these lines have to have their separation. There's going to be wind turbines, you know, between lines. And you've got to allow for that. If you have a 3500-foot-wide corridor, that isn't all utility. It's got to be utility, wind turbine, follow the BLM multiple use. Let the utilities have their corridor, but let the wind turbines do their thing, too.

So, I think that's pretty much it. And I think, again, the beef up upgrades into the load center, and there you are.

PRESIDING MEMBER PFANNENSTIEL: Thank you. Chuck, do we have another panel to go?

MR. NAJARIAN: Yes, we do. And I'll ask them to go as quickly as possible.

We have a small panel --

PRESIDING MEMBER PFANNENSTIEL: Thank you all, this panel. I appreciate your --

MR. NAJARIAN: Thank you for the developers.

-- a small panel comprised of agencies. Duane Marti, BLM. Gary DeShazo, Cal-ISO. And over the Webex we've got Lorelei Oviatt, the Planning Division Chief with Kern County.

MS. OVIATT: Yes.

MR. NAJARIAN: And Jim Squire with San Bernardino County.

PRESIDING MEMBER PFANNENSTIEL: May I ask as the panel gets all settled, out of respect for the parties who are still here, and wanting to finish the day, that we really appreciate new ideas and comments, answers to these questions that haven't already been presented.

I think we can -- it's been a long day with a lot of information. And so we really appreciate people who are willing to stay and address us even at this late hour.

So if you can really focus on what hasn't been said yet, we'd appreciate it. Thank you.

MR. MARTI: I'd much rather go home and have a beer, so I will be short.

(Laughter.)

MR. MARTI: Basically from the first question from --

PRESIDING MEMBER PFANNENSTIEL: Excuse me, Jim, would you identify yourself for the record?

MR. MARTI: I'm Duane Marti from the BLM. Not Jim.

I agree that the regulatory issues involve many federal and state and local issues. And I would agree with the gentleman from SMUD, we need cooperation and coordination between the agencies, so we're not asking the applicant the same question four different times.

And I agree with Ms. Hapner's comment about using the hydro relicensing model as a good model for working. It has been working well from the feds and the other agencies in the relicensing; and I think that's a very good one.

Question number two, I think of the three points that you make, we, the federal agencies, would love to have that information. It would help us work with our processing the applications that we have in front of us, if we know which application will be most beneficial to you, that's the one we'll work on.

I have no further comments.

PRESIDING MEMBER PFANNENSTIEL: Good comments, thank you. Gary.

MR. DeSHAZO: That certainly was quick, and the beer actually sounded pretty good, as well.

(Laughter.)

MR. DeSHAZO: I guess let me just very quickly when we first moved here, my son tried out for a soccer team, competitive soccer. He didn't know anybody, but as he was standing out there he was very concerned about going out there and trying out. He was giving me all the reasons why he didn't think it was a good idea for him to go out and play soccer.

So, let me just start with that. And then what I've heard today in terms of the comments with regard to the transmission impediments or barriers to getting renewables connected, and I guess for that matter for any transmission, is that, you know, -- and let me just say for the record that yes, the ISO acknowledges the fact that there are difficulties and issues with participating with other entities in building transmission. Okay. Can we just get past that?

My son went out, started playing soccer; and in fact, he's now playing varsity soccer at Oak Ridge High School. So he did very well.

I've been planning for a very long time, and I can tell you without hesitation that there is no relationship between coming up with a transmission plan that makes sense for California and who pays for it. Okay.

You can't have the latter unless you figure out what it is that you want to do. I have been coming in here and speaking in front of you for over a number of occasions, a number of times, a number of reasons, and it always seems to boil down to, well, we just can't work together.

As you know, over the past year and a half I have been out there preaching subregional planning. The ISO has implemented a planning process. If you look at that process it's very clearly designed to interact with all of our control area neighbors, the nonjurisdiction utilities, anybody else that will work with us we're interested in working with.

And the thing about this is I wasn't sure that I really understood this until Mr. Braun's comments was along the lines of where we started and what we thought we were going to do, and where we are. We don't seem to be making any progress. And he's right, we're not.

And I think we need to get past this aspect about the fact that you have difficulties about who operates, you know, who pays for, let's get to the point where we need, we can do the planning and we can decide what is the right transmission infrastructure for the State of California.

Unless we have that answer, I don't believe that you and others that have a responsibility for helping and managing make this happen can do it, because you don't have anything to work with.

And so, you know, my answer to the

impediments and the barriers is let's get on with it. Okay, we're ready to go. We've been ready to go for the past year. My challenge to the others that I have been talking to is step up and let's go. So we can get something put together and we can bring something to you that shows that there's been at least a thoughtful coordinated process looking at the overall transmission planning and the needs for California.

Our interests have always been in working with the Energy Commission and the Utilities Commission. I believe that this is absolutely important to be done because you bring a lot to the table that needs to be considered upfront.

Which brings me to the second challenge, what I need. And I think what we really need from the Energy Commission is some signals about where we think the renewables can be developed. You know, if we want to try to find where the best places are to interconnect, or maybe where the corridors are, it seems to me that that's a little bit ahead of the game.

I think we need to decide where they are. And then we need to have a process in place that helps us manage or understand where are the best places to go after.

You may identify five or ten different locations that, you know, throughout California where renewables could possibly develop. But maybe only half of those, or maybe even 20 percent of those are ones that can be easily interconnected in the system in a way such that we can show, well, if we build a trunk line out there, so to speak, if I'm to use that word or that term, then at some point in time we can build another transmission line to that same point and actually interconnect it into the grid; and be able to show that there's a benefit to the overall grid for doing that.

I firmly believe that our planning process is capable of doing these kinds of things. And that we can bring before you a transmission plan, a strategic plan that says we can take this step today; and five or ten years later, if we take this next step, we believe that there will be benefits that will come from that.

But the ISO really can't do that on its own. The PTOs are very committed to this overall process. But we've got to break these other barriers down and move forward so we can get others involved, because there are people that are very interested in wanting to move forward and be involved in this process.

ASSOCIATE MEMBER GEESMAN: In terms of identifying the renewable resource areas, what level of granularity is most helpful to you?

MR. DeSHAZO: I think this is, unlike the load forecasting thing that we had discussed with you before, I don't think it needs to be anywhere near that granular. You know, if you look at Tehachapi, it's an area -- California is pretty large, but the key is that there's some transmission infrastructure that would support that.

I think that as we work with one another we can probably better define exactly what those things are. It depends upon what the Commission's capabilities are and what they can deliver, as opposed to what we can, you know, what we need in order to be able to perform an analysis.

But I think that there's a reasonable balance that can be struck there.

PRESIDING MEMBER PFANNENSTIEL: Robin.

MS. SMUTNY-JONES: I only have about 25

slides.

(Laughter.)

PRESIDING MEMBER PFANNENSTIEL: That's fine.

MS. SMUTNY-JONES: Just wanted to scare everybody. Actually I just got back from Jamaica so it's rum punch that sounds really good right now.

No, really, I just wanted to say a couple of things on behalf of ISO here at the end. Tony Braun got up a little bit ago and talked about how we actually did work together on the third category proposal and declared that they weren't opposed to it.

And I have to say that that was one of the more pleasant interactions that we've had with the municipal community in some time. And I really do think that we had some constructive work go on, and we were able to put the proposal into shape in a way that it made sense. Whether it comes out with a settlement process or not, I don't know.

But I think the point is that the Energy Commission can provide a platform for us to work together. We do have the Swiss cheese in

California. I don't think it's going to go away anytime soon.

We've got the federal entity; we've got the, you know, the cousin thing that we are, or whatever, you know. We're going to be the Swiss cheese for awhile. And the Energy Commission can provide that service in that role of bringing everybody together to fulfill this dream that Gary brings forth on subregional planning. Because that's really what needs to happen.

We are sensing a little bit more willingness on the part of the municipal utilities to come to a table, as long as it's not just our table, or a FERC table. And this might be the one where we can all really come together and look at a grid plan that makes sense.

So we appreciate all your efforts to date, and look forward to working with you.

PRESIDING MEMBER PFANNENSTIEL: Thank you; those are good observations.

On the phone?

MR. NAJARIAN: Right. We have Lorelei Oviatt of Kern County. Lorelei, are you able to speak with us?

MS. OVIATT: Yes, Lorelei.

MR. NAJARIAN: Lorelei, I'm sorry. Yes, go ahead.

MS. OVIATT: That's okay. I really appreciate you inviting me. As a local agency I have the Tehachapi area, plus I have all of the, most of the desert areas, along with a large new burgeoning biomass industry up here in the Valley. So every day I'm dealing with these issues.

And I really appreciate the technical information that I got after listening during the day.

I do want to bring some new thoughts to you. One of them is one of the barriers is we have a communication gap. And the gap is that you're working closely, developers are working closely, utilities are working closely, and I'm getting my information from The L.A. Times or The Wall Street Journal.

We have a discretionary action that has to happen, and many local agencies have them. And we're not getting included in the process. The California Energy Commission has been extraordinary in reminding applicants and utilities that they're supposed to be talking to local government.

But I'm going to bring you a new idea. Where you put your transmission line actually creates land uses. And what we want to do, and what we have been trying to do is say to the utilities, don't put them there. Put them where the renewables should go.

Kern County has encouraged the wind industry and the military to work out this red, yellow, green map which we adopted, which provided a lot of direction in defining, you know, these are areas where you can put wind energy. And these are areas where we think it's a conflict.

I completely agree with the representative from enXco and many other developers who have spoken, who want certainty in this process. I want that, too.

And so none of these ideas that I would like to see the Energy Commission help us with is educate local government on the variety of impacts that the various kinds of renewables, you know, bring into our process.

For example, I would like to see you somehow, maybe with the industry, give us a handbook. I know there are a variety of different ways that solar can be done. I don't have any sort of resource, an easy resource that I, as a planner, when I'm doing my general plans, when I'm looking at my energy element, which I happen to have one, an energy element. You know, what are the varieties of technologies. How much space did it take up; what kinds of vertical obstructions do they cause.

I think that the Energy Commission could be a leader in this and actually create a handbook for local governments such that we could work on this very issue of programmatically identifying in our counties here are the areas where renewables would be good; here are the areas where there's just too many conflicts.

I think that a tool such as this, in conjunction with the kinds of land use planning that local government is used to, would also provide kind of a heads-up early-warning system, the kind of fatal flaw analysis that the utilities are already engaged in, in regards to where their transmission lines could go.

And we see this as here in Kern County, besides the red, yellow, green map that we've already done for wind, we're already very interested in working on designing for the rest of our 3000 square miles of desert, you know, where should we put solar; where can we work with the Department of Defense to decide how to integrate these things. And along with Fish and Wildlife and other agencies.

So, that's my idea at the end of the day, which is another, you know, another tool for local government; along with encouraging the Energy Commission to continue to encourage everyone to talk to us. Please come see us early.

PRESIDING MEMBER PFANNENSTIEL: Thank you very much. Good thoughts.

MR. NAJARIAN: Thank you. Next up we have Jim Squire with San Bernardino County, on the Webex.

MR. SQUIRE: Thank you for inviting me to speak. I will be really brief because most of what I was going to tell you has already been mentioned by previous speakers.

We think the biggest -- one of the biggest constraints or barriers to these projects is the review process. One of the primary aspects of that is the environmental review process. So we would really support the programmatic approach, the EIR/EIS approach that was mentioned by the BLM representatives, from which specific projects could be tiered from. And help minimize the cost, expense and time of doing a full environmental analysis on every single individual project. So we would really support that.

We were encouraged to hear about the push from all the speakers about there needs to be more collaborative effort and a greater number of stakeholders represented at the table, of which we would be one. And in our jurisdiction, as in Kern, they've been working with the military.

And I'm not here to speak for the military, but I know they are very concerned about the height of these towers, whether they're wind energy or whatever.

And as well as had been mentioned earlier by the representative from enXco about the radar aspect of these projects really impacts some of their missions. So they need to be a part of this discussion, as well. And I know BLM said that they were. So we were encouraged by that.

We think that these corridors and the resource areas should be identified. And once they are identified we need to, the local jurisdictions need to know, you know, have a GIS database of where these corridors are. Just like the military has given us a database of their low-level flying routes. And it's made it much easier for us to identify these on maps. So we can identify and notify people who have property underneath these corridors that they are within a corridor.

Having a GIS database would help us to perhaps put in regulations that we need to about what are the compatible uses. And I know BLM was talking about that, as well, as far as developing a list of compatible uses.

And we would encourage that. And it would help local jurisdictions to identify those uses that could be compatible within these corridors, or adjacent to these corridors. And not only would it help in developing the actual transmission projects, but also those projects within those areas that could proceed on, because they've been determined to be compatible. So we would encourage that.

There is a precedent in the Government Code similar to the -- in the regulations relative to the ag preserves. They have a list of compatible uses. And it really does help the jurisdictions to implement those and to put it in their own codes as far as what is compatible and what is not.

Once these are identified and we have the same map, local jurisdictions will probably do something like an overlay to help county staff and the public to identify, you know, where these areas are. Am I within a corridor, am I not. What are the constraints. Easily notified if there is a project within these corridors, and it would help expedite all that coordination that needs to be done in the review process of specific projects.

So, I would reiterate all those other comments that have been made previous, and I really don't have anything else to add.

PRESIDING MEMBER PFANNENSTIEL: Thank you. We do have a blue card from one person who'd like to speak. Charles Toka. Is he here?

MR. POWERS: I'm not Charles. I intended to speak, but --

PRESIDING MEMBER PFANNENSTIEL: Oh, is Charles Toka here? I have this blue card.

Why don't you address us; come to the mike, please.

MR. POWERS: And I will legitimately be brief, maybe a minute. Bill Powers, Border Power Plant Working Group down in San Diego.

And I did bring five copies for each Commissioner of our request that the DOE reject SDG&E's request for national interest electric transmission corridor designation. And I won't go into that, but I will make sure you get copies of that.

I was a part of the Imperial Valley study group process. And I do want to point out that it is difficult -- I'm a consulting engineer by day, and an activist by night -- and it's difficult for the public to attend all-day meeting that are held during the week wherever they might be.

So you shouldn't be surprised if there is an entity like this where you get agencies, but it's tough to get public interest folks there.

One of the issues in the Imperial Valley study group process that was unacceptable to the intervenors was the presumption that the transmission from Imperial Valley had to carry 2000-plus megawatts on a single line. That was a premise. That eliminated all upgrade options, all iterative options other than essentially the Sunrise Power Link.

Down in San Diego we have a process through the San Diego -- SANDAG, San Diego Area of Governments, all the mayors. Our goal in San Diego is to increase in-area generation. That's a target.

The Sunrise project conflicts with that target. As a result, SANDAG has taken a vote of no position that was unanimous by the mayors on Sunrise because of this conflict.

And the CEC does have a hand in both of those solutions. You permit new power plants. We have modernization of our plants as a goal. We have a Dynegy project, used to be Duke, LS Power; air cooled, combined cycle, absolutely state of the art. NRG is proposing the same type of upgrade. That's our alternative to this line.

There is generalized concern that this project is really to enhance the parent company of SDG&E, Sempra's ability to export power from their export assets in Mexico to ultimately Los Angeles. I see this as Valley Rainbow 2. If Sunrise is just an iteration of an earlier project.

And so what I would ask, and one other

comment before I end, and that is that in the PUC process, which I actually like, we're kicking the tires on all sorts of different options there, SDG&E has been required to model the ability to import renewable power from Imperial County if we go with combined cycle option and we don't build Sunrise.

They are modeling a spectacular amount of renewable energy delivery, over 100 percent of our annual energy needs in 2015. And under that scenario it's all deliverable. Not only that, the localized market price of power doesn't change, whether we add Sunrise or we add the combined cycle.

And so all I would ask the Commissioners is that you keep an open mind about how we solve this issue. And that you not see accepting Sunrise, as it has been proposed by SDG&E, that failure to do that is a failure of the system. I think we'll get a good solution, whether we get Sunrise Power Link or not.

Thank you.

ASSOCIATE MEMBER GEESMAN: Bill, has SANDAG taken a position on the South Bay Power Plant?

MR. POWERS: What's happening at South Bay is the Port has rejected the site as the replacement site. Chula Vista has formed a committee, which I'm on, to identify alterative sites within the city limits of Chula Vista for the project. That was part of that deal to reject that site.

And so hopefully within two months time you will have a series of, or at least Dynegy will have a number of alternatives that the City has proposed for the facility.

ASSOCIATE MEMBER GEESMAN: But has SANDAG involved itself in any way?

MR. POWERS: SANDAG has involved itself to the extent that they have made it a priority to get replacement combined cycle projects for the two coastal boiler plants that we have.

The SANDAG has involved itself only to the extent to say that we can't have individual cities within the County of San Diego freelancing and rejecting our overall plan, which is happening now. And so SANDAG is in a process, through the energy working group, of saying let's get in a room, shut the door, and figure out where we're going to put the new combined cycle plants locally so we're not in a public process of clashing.

ASSOCIATE MEMBER GEESMAN: And NRG, just within the last month or so, took some action regarding their commitment to a combined cycle at Encina, did they not? They joined with another company for the Miramar project, and were going to contribute offsets from Encina to the Miramar project, and replace Miramar with -- or replace Encina with potentially a peaking unit?

MR. POWERS: Commissioner, you have a very up-to-date understanding of what is happening in San Diego. And it is somewhat complex. And at the moment, the NRG has joined the private developer who has the option to develop a site on the Miramar Marine Corps Air Station.

And they have also proposed to build a frame-sized peakers at the current site of the Encina Power Plant.

And I would expect that this picture will become somewhat clearer over the next few months. But to be fair to these independent power producers, SDG&E holds virtually all the cards. And we have a SANDAG objective to get additional in-basin generation. But if we can't get the utility to offer long-term power purchase agreements to these independent power producers, it will not happen.

ASSOCIATE MEMBER GEESMAN: Okay, thanks.

MR. POWERS: Thank you.

PRESIDING MEMBER PFANNENSTIEL: Do we have Charles Toka here?

MR. NAJARIAN: I don't believe we do.

PRESIDING MEMBER PFANNENSTIEL: All right. Any other comments, anything else?

MR. NAJARIAN: We're going to go ahead and unmute everybody right now, see if there's any comments from people on the phone.

Any comments? No.

PRESIDING MEMBER PFANNENSTIEL: Hearing none, we'll be adjourned.

(Whereupon, at 5:05 p.m., the Joint Committee Workshop was adjourned.

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CERTIFICATE OF REPORTER

I, PETER PETTY, an Electronic Reporter, do hereby certify that I am a disinterested person herein; that I recorded the foregoing California Energy Commission Joint Committee Workshop; that it was thereafter transcribed into typewriting.

I further certify that I am not of counsel or attorney for any of the parties to said workshop, nor in any way interested in outcome of said workshop.

IN WITNESS WHEREOF, I have hereunto set my hand this 3rd day of May, 2007.

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